BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 2008-0303
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	
MAUI ELECTRIC COMPANY, LIMITED	)	
	)	
For Approval of the Advanced Meter Infrastructure (AMI) Project and Request to Commit Capital Funds, to Defer and Amortize Software Development Costs, to Begin Installation of Meters and Implement Time-Of-Use Rates, for Approval of Accounting and Ratemaking Treatment, and other matters.	)	

Advanced Metering Infrastructure (AMI) Project

HECO Companies' Responses to Information Requests

June 5, 2009

Hawaiian Electric Company, Inc. • *PO Box 2750* • *Honolulu, HI 96840-0001*

Dean K. Matsuura
Manager
Regulatory Affairs

June 5, 2009

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0303
Advanced Metering Infrastructure Project
HECO Companies' Responses to Information Requests

In accordance with the *Order Approving Stipulated Procedural Order, as Modified*, filed on April 21, 2009, enclosed for filing are the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited's responses to the information requests submitted by Life of the Land (dated April 29, 2009), the Division of Consumer Advocacy (dated May 8, 2009), and the joint information requests submitted by the Hawaii Solar Energy Association and the Hawaii Renewable Energy Alliance (dated May 8, 2009).

Very truly yours,

Enclosures

cc: Division of Consumer Advocacy
Henry Q Curtis (Life of the Land)
Warren S. Bollmeier II (HREA)
Mark Duda (HSEA)

CA-IR-1

Ref: Application

On various pages of the application, the Companies indicate that the proposed project will replace approximately 95 – 96% of the commercial, industrial and residential electric meters.

a. For each company, please identify the planned roll-out schedule by geographical area for each customer class. For purposes of this question, please ignore the service visits that will be required to install the "first requested" meters by early adopters.
b. Please discuss why there will be four to five percent of customers that will not receive the proposed AMI meters.
c. If not already discussed earlier, please provide the customer type and probable geographical location of the customers not expected to receive AMI meters.
d. If not already discussed, please discuss whether the customers expected not to receive the AMI meters will be able to receive the same level of benefits as other customers with AMI meters.
    1. If not, please discuss whether these customers should be required to contribute to the overall costs of the AMI project.
    2. If it is the Companies' position that these customers without AMI meters should contribute to the overall costs of the AMI project even if they cannot receive the same level of benefits as all other customers with AMI meters, please discuss whether the Companies have considered recovering some, but not all, of the allocated costs of the AMI project from these customers.
        (a) If the Companies are willing to recover some reduced amount of cost recovery from these customers not expected to receive the same level of benefits, please provide the assumptions and calculations that would be used to determine the amount recoverable from these customers.
        (b) Please provide a copy of all workpapers, calculations and other supporting documentation used to develop the Companies' response.

<u>HECO Companies' Response:</u>

a. Exhibit 18 of the Application presents the overall project schedule including the meter deployment for each company. The timeframe for meter deployment is shown below:

Company	Planned Meter Deployment
HECO	2011 - 2013
MECO	2014
HELCO	2015

A more detailed deployment plan will be developed prior to meter deployment in consultation with the AMI vendor to utilize the vendor's experience in other mass meter deployments. From an efficiency standpoint, the Companies expect to focus on geographic areas and meter reading routes, and all customer classes will be included.

b. The HECO Companies are unaware of any AMI network solution that would provide for 100% coverage. To establish the cost effective network coverage for the HECO Companies, Sensus Metering Solutions ("Sensus") (the selected AMI vendor) performed a detailed network design, which was included as Exhibit D of the Sensus Agreement (executed on October 1, 2008). In the Executive Summary of Results (Sensus Agreement, Exhibit D, page 2), Sensus presents the expected customer coverage for HECO (95%), MECO (96%) and HELCO (96)%. Several products are available (e.g. FlexNet Remote Portal-FRP and FlexNet Network Portal-FNP) from Sensus to extend AMI network coverage to additional meters, but uncovered areas will remain.

The premium cost of Sensus AMI meters is partially attributed to radio communications capability; therefore, at customer sites without network coverage, the Companies had not originally planned to install AMI meters. Since residential AMI meters are less expensive than non-AMI meters for situations requiring time-of-use ("TOU") billing and in-home displays, which may be provided in future programs, the Companies propose to update their Application to install AMI meters for all non-MV90 and non-Turtle customers.

c. HECO planned to replace 95% of its non-MV90 meter population, while MECO and HELCO planned to replace 96% of their non-MV90 meter populations[1]. Graphical representations for covered and uncovered areas are shown in Exhibit D of the Sensus Agreement (pp. 3,14, and 19 for HECO, MECO, and HELCO respectively).

d. Customers that do not receive AMI meters may not receive the same benefits as customers who have AMI meters. For customers that are situated in areas without AMI network coverage, the Companies had not planned to install an AMI meter; however, the Companies now plan to install AMI meters for all customers so that the maximum number of customers can benefit from participation in TOU programs. The response to CA-IR-35 updates Exhibits 19, 21 and 22 to include these additional costs, as well as the impact of other updates explicitly identified in the response.

Customers without AMI network coverage may also benefit in the future from an in-home display that communicates directly with the AMI meter to provide interval data. Docket 2008-0303 does not include costs to provide such displays to customers; however, the Company indicated in the Application (footnote on page 25) that this could be a future request.

Although an AMI meter is more expensive than a non-AMI meter, it is very cost effective in capturing interval data and storing this data in TOU registers. As a result, this type of customer could benefit from being a TOU customer. The programmability of the AMI meter allows TOU-framed data to be stored and displayed by the meter;

[1] MV90 is an Itron software product which is used to collect interval data from selected customer meters which are connected to phone lines.

therefore, the meter can be read manually in the limited situations where AMI network coverage cannot be made available economically.

1. The Company's position is that all customers should contribute to the overall costs of the project since the collective impact of the AMI Project will have benefits for all customers. The specific extent to which each individual customer benefits from the AMI Project would be virtually impossible to determine and therefore impractical to use as a basis for allocating cost to each customer.

2. The Companies have not considered apportioning AMI project costs differently for customers with AMI meters and those without AMI meters. If AMI meters are provided to customers who are outside the AMI network coverage area, the apportionment question will be minimized.

    a. See response above.

    b. Since the Companies have not proposed a method to apportion AMI project costs differently for customers with AMI meters and those without AMI meters, no assumptions, calculations, workpapers or other supporting documentation are available.

CA-IR-2

Ref: Quantifiable Benefits - Application and Exhibits 15 and 19.

On page 7, the Company asserts that the incremental revenue requirements for the proposed project include the offset from "the benefits of automating meter reading and certain field service activities, revenue enhancements from improved meter accuracy, and reduced electricity theft." Exhibit 15 presents a list of AMI benefits, and Exhibit 19, Table 12 provides the quantifiable benefits.

a. Please provide copies of the workpapers used to develop the estimated quantifiable benefits associated with the implementation of AMI.
b. If not already included with the response to part a. above, please identify all assumptions used to develop the estimated quantifiable benefits and include a discussion of why the assumptions are reasonable. If applicable, please provide the historical and all other supporting information relied upon by the Companies to develop its assumptions.
c. Please confirm that the items and the related estimates are the Companies' best attempt to quantify the total benefits/savings at this time. If this understanding is incorrect, please provide a schedule with the Companies' best attempt to quantify the total benefits/savings associated with the proposed project. Please include copies of all workpapers used to develop the estimates and provide a discussion of why each assumption was used to develop the estimates and why it was reasonable to make that assumption.

HECO Companies' Response:

a. Please see Attachment 1 to this response (AMI Model Version 1.1), which provides the underlying assumptions regarding the costs and benefits estimated in the AMI Application. Please see Attachment 2 to this response for a detailed narrative explaining the AMI Model. The quantifiable benefits and their assumptions are covered in the following sections of Attachment 1 to this response:

Section (VIII) OAH – Meter Hardware Benefits – pages 68 through 69
Section (VIII) HEL – Meter Hardware Benefits – pages 70 through 71
Section (VIII) MAU – Meter Hardware Benefits – pages 72 through 73
Section (IX) OAH – Meter Reading Benefits – pages 74 through 75
Section (IX) HEL – Meter Reading Benefits – page 76
Section (IX) MAU – Meter Reading Benefits – pages 77 through 78

Section (X) OAH – Field Services Benefits – pages 79 through 80

Section (X) HEL – Field Services Benefits – pages 81 through 82

Section (X) MAU – Field Services Benefits – pages 83 through 84

Section (XI) OAH – Ratepayer Benefits – pages 85 through 86

Section (XI) HEL – Ratepayer Benefits – pages 87 through 88

Section (XI) MAU – Ratepayer Benefits – pages 89 through 90

b. All assumptions are covered in part (a) above and the following attachments are provided to document the origination of the assumptions:

Attachment 3 – Non-AMI Meter Comparison Pricing

Provided by Gerritt Lee (HECO Meter Engineer)

Attachment 4 – 2007 – 2012 Customer Forecast

Provided by Cathy Hazama (HECO Sr. Planning Analyst)

Attachment 5 – 2007 – NEM-CID_fORECAST_2008-2012

Provided by Lance Kimura (HECO Meter Supervisor)

Attachment 6 – AMI Meter Reading and Field Services Savings

Provided by Customer Service (HECO)

Attachment 7 – Percent of Variable Revenue to Total Revenue

(HECO 1995 test year rate case, Docket No. 7776 Decision and Order NO. 14412)

Attachment 8 – 2007 Test Year Generation

(HECO Docket No. 2006-0386)

AMI Application, Exhibit 16 – Accuracy Tests of EM vs. Sensus Meters

Provided by Ralph Earle (HECO Research Analyst)

Attachment 9 – EPRI Revenue Loss Assessment (EPRI)

Attachment 10 – AMR for Theft-Chartwell (Chartwell)

Attachment 11 – SDG&E AMI Application Chapter 29 (PUC State of California)

Attachment 12 – HECO Energy Theft Estimates

Provided by Kazuo Shirakawa (former HECO Director, Business & Economic Analysis)

c. The information in the Companies' response to parts (a) and (b) represents the Companies' best attempt to quantify the total benefits/savings of the AMI Project at this time. Copies of the workpapers and backup documentation used to develop the estimates are attached to this response.

CA-IR-2
DOCKET NO. 2008-0303
ATTACHMENTS 1-12

Attachments 1-12 are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the documents. Electronic copies of the requested information are being provided.

CA-IR-3

Ref: Quantifiable Benefits - Application and Exhibits 15 and 19.

a. Please provide the estimated pay back period associated with the proposed project broken down by each company (i.e., HECO, HELCO, MECO).
   1. Please include copies of the workpapers used to develop the estimates.
   2. Please break down the pay back period by each individual company. Please include copies of the workpapers used to develop the allocated factors and to develop the savings per company.
b. If the Companies have not developed a pay back analysis, please explain why not.

<u>HECO Companies' Response:</u>

a. The company computed a Benefit/Cost Ratio for the AMI Project and the results are provided in Attachment 1 to this response. The Companies' estimate of quantifiable costs and benefits indicate that the AMI Project has a non-discounted Benefit/Cost Ratio of 1.31 for HECO, 1.12 for MECO, and 1.10 for HELCO. Simple payback periods for HECO, MECO, and HELCO are 13, 17, and 20 years respectively as shown in Attachment 4 to this response. The Companies' estimate of quantifiable costs and benefits indicate that the AMI Project has a discounted Benefit/Cost Ratio of 0.73 for HECO, 0.64 for MECO, and 0.64 for HELCO. Future programs that are enabled by AMI such as Demand Response will improve these estimated Benefit/Cost ratios.

Section D.2 (page 45) of the Application discusses the intangible benefits that the AMI System will support. AMI is a platform upon which future applications and programs will be built. The September/October 2007 issue of Electric Perspectives (a publication of the Edison Electric Institute) is provided as Attachment 2 to this response. Page 5 (68 in the publication) of Attachment 2, Figure 2 – "Smart Grid: Where Benefits Start", shows the improved benefits as these new programs are implemented. Attachment

3, Southern California Edison "Testimony Supporting Application For Approval of Advanced Metering Infrastructure Pre-Deployment Activities and Cost Recovery Mechanism, Volume 1 – Overview of SCE's AMI Deployment Strategy and Objectives, Section II, page 4 demonstrates the need for additional programs such as Net Price Response and Net Load Control to achieve benefits which exceed costs.

b. Not applicable.

Attachments 1-5 are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the documents. Electronic copies of the requested information are being provided.

CA-IR-4

Ref: Quantifiable Benefits - Application and Exhibits 15 and 19.

a. Please confirm that the Companies have not estimated or calculated any other quantifiable savings other than that presented in Table 12 of Exhibit 19.
b. It does not appear that the Companies have estimated any savings related to reduced emission fees related to the probable reduction of emissions if the Companies are able to rely on the AMI and various TOU and other options that will allow the Companies to use their systems more efficiently. Please discuss.
c. Please discuss whether there should be any recognition of the possible additional generation capacity benefits where the use of AMI technology might allow the Companies to dispatch generation units in a more efficient manner than was assumed in the most recently completed rate proceeding for each company. Please provide copies of any analyses or studies that support the Companies' response and the quantification of any such benefits.
d. Please discuss whether there should be any recognition of the possible reduction in customer accounts and/or services expenses that would be related to reduced customer calls for various reasons (e.g., less questions/complaints about estimated bills). Please provide copies of any analysis or studies that support the Companies' response and the quantification of any such benefits.
e. Please discuss whether there might be any savings related to reduced injuries or other related accidents attributable to meter readers and/or the vehicles used by the meter readers. Please provide copies of any analysis or studies that support the Companies' response and the quantification of any such benefits.
f. Please discuss whether the implementation of AMI technology will improve the billing cycle efficiency such that the working cash lag might be reduced. Please provide copies of any analysis or studies that support the Companies' response and the quantification of any such benefits.
g. Please discuss whether the implementation of the proposed AMI technology will result in the obsolescence of other meter reading technologies that the Companies currently have in place (e.g., reading meters using equipment in a van reading transmitted data, etc.). Please provide copies of any analysis or studies that support the Companies' response and the quantification of the net benefits associated with the implementation of AMI technology.

<u>HECO Companies' Response:</u>

a. The Companies have updated their estimated and calculated quantifiable savings and have submitted in the update in their response CA-IR-35, Attachment 1, Table 12 (AMI

Benefits). The companies have not estimated or calculated any other quantifiable savings other than those presented in their response to CA-IR-35.

b. The proposed Time-of-Use ("TOU") Rate options and other future options may have a beneficial impact on energy efficiency. AMI will also facilitate or enable the development of other programs which could have future impacts on energy efficiency. However, the companies do not have a basis for attempting to quantify any significant reduced emission fees related to the reduction of emissions due to the implementation of AMI and TOU rates or other future programs. See also response to part c.

c. The Companies are not aware of any basis for assuming that the use of AMI technology might allow the Companies to dispatch generation units in a more efficient manner than was assumed in the most recently completed rate proceeding for each company.

d. Initially, the Companies do not expect a reduction in customer accounts and/or services expenses that would be related to reduce customer calls for various reasons (e.g., less questions/complaints about estimated bills). In fact, Exhibit 14, Section II.A (Change Management) of the AMI Application states:

> *Customers calls are expected to become more complex, involving for example, AMI meter exchanges, potential rate options and energy efficiency programs, energy usage information, DR device operations, etc.*

This results from the introduction of a new technology (AMI), new sources of information (customer web portal), and new rates (TOU). Over the long term, as customers become more educated about the technology, it is conceivable that customer inquiries may decline. However, the Companies have no data or analysis to support any expense reduction resulting from such a scenario.

e. All of the following costs were taken into account when calculating the benefits meter reader benefits:

- Labor Costs (BU, including overhead)
- Labor Costs (merit, including overhead)
- Non-Labor Costs (including materials & supplies, excluding Outside Services)
- Transportation Costs
- Outside Services

The workpapers for the calculation of meter reader benefits are provided in the Companies response to CA-IR-2. Potential savings related to reduced injuries or other related accidents attributable to meter readers and/or the vehicles used by the meter readers were included in the analysis of the Labor Costs (BU, including overhead) and the Transportation Costs.

f. The Companies are not aware of any analysis or studies to support the quantification of any improvement to the billing cycle efficiency such that the working cash lag might be reduced due to the implementation of AMI technology.

g. Implementation of the proposed AMI technology will only result in the obsolescence of the Turtle meter reading system. The use of the other historic meter reading technology (MVRS) will be reduced, which will result in a reduction in the maintenance cost of that system. The elimination of the Turtle system and the other reduced maintenance costs are reflected in the reduction in meter reading Outside Service included in the meter reading benefits. The workpapers for the calculation of the meter reader benefits are provided in the Companies response to CA-IR-2.

CA-IR-5

Ref: Quantifiable Benefits - Application and Exhibits 15 and 19.

a. Please identify the historical O&M expenses, excluding meter reading expenses, related to existing non-AMI meters for each of the past five years for each company.
b. Please discuss whether the Companies anticipate O&M expenses, excluding meter reading expenses, to be greater or less than for AMI meters in comparison to non AMI meters. Please provide copies of the documentation and analyses relied upon by the Companies that support the response.

<u>HECO Companies' Response:</u>

a. The Companies identified the O&M expenses, excluding meter reading expenses, as Field Service Savings. The historical O&M expenses, excluding meter reading expenses, related to existing non-AMI meters for each of the past five years for each company are provided with this response as Attachment 1, Attachment 2 and Attachment 3, for HECO, MECO and HELCO, respectively.

b. The Companies anticipate O&M expenses, excluding meter reading expenses, to be less for AMI meters than for non-AMI meters. The Companies' response to CA-IR-2, Attachment 1, Section X provides the complete analyses on the Field Service Benefits related to the Companies' AMI Project. In addition, the Companies' response to CA-IR-2, Attachment 2, Section X provides a narrative explanation for the analyses on the Field Service Benefits.

HECO Field Services O&M Costs	2007 Budget (Thou)	2004 Actual (Thou)	2005 Actual (Thou)	2006 Actual (Thou)	2007 Actual (Thou)	2008 Actual (Thou)
Labor Costs (BU & Merit, incl. overhead)	**1,806.73**	**$1987.9**	**$2128.6**	[3] **$2267.0**	[3] **$2454.9**	[8] **$2629.2**
Non-Labor Costs (incl. materials & supplies, excl. Outside Services)	**48.93**	**$41.1**	**$19.3**	**$38.2**	**$25.0**	**$51.1**
Transportation Costs	**129.16**	**$97.5**	**$124.0**	[5] **$153.2**	[7] **$170.2**	**$146.9**
Outside Services	**68.70**	[2] **$98.6**	[2] **$27.0**	[4] [6] **$127.4**	[6] **$140.7**	[6] **$154.2**
Total Field Services O&M Costs	[1] **2,053.53**	**$2225.2**	**$2298.9**	**$2585.8**	**$2790.8**	**$2981.4**

NOTES

[1] The 2007 Budget amounts used in the business case excluded the budgeted costs for the Revenue Protection and Senior Investigation Sections of $507,000. These sections are included in the 2004 - 2008 reported Actual amounts because we are unable to provide an accurate breakout.

[2] Increased outside service costs for new maintenance support fees for mobile field management equipment. 2005 outside service costs for new maintenance support fees for mobile field management equipment was paid in 2004.

[3] Increased labor costs for overtime to reduce backlogged work.

[4] Increased outside service costs for new maintenance support fees for mobile field management equipment.

[5] Higher transportation costs due to additional use of pool cars in addition to the field services fleet.

[6] Increased outside service costs due to expanded use of a revenue protection consultant.

[7] Higher transportation costs due to increased vehicle rates.

[8] Higher labor costs due to increased OT for credit related work and high bill investigations and retro wage increases back to November 2007.

Field Services O&M Costs	[1] 2007 Budget (Thou)	2004 Actual (Thou)	2005 Actual (Thou)	2006 Actual (Thou)	2007 Actual (Thou)	2008 Actual (Thou)
Labor Costs (BU & Merit, incl. overhead)	$640.8	$466.3	$475.2	$493.0	[4] $527.8	[6] $655.5
Non-Labor Costs (incl. materials & supplies, excl. Outside Services)	$55.2	[2] $42.0	[2] $26.4	[3] $30.4	$28.5	$33.6
Transportation Costs	$65.9	$70.5	$68.3	$59.9	[5] $82.2	[7] $119.5
Outside Services	$4.4	$8.0	$9.5	$6.2	$7.2	$4.5
Total Field Services O&M Costs	$766.3	$586.8	$579.4	$589.4	$645.7	$813.0

NOTES:

[1] The 2007 Budget amounts used in the business case excluded Revenue Protection and Investigation Sections. These sections are included in the 2004 - 2008 reported Actual amounts because we are unable to provide an accurate breakout.

[2] Lower non-labor costs due to lower materials spending (load limitors) in 2005 compared to 2004.

[3] Higher non-labor costs in 2006 compared to 2005 as materials spending returned to normal.

[4] Increased labor costs with addition of a new Field Representative.

[5] Higher transportation costs due to increased vehicle rates.

[6] Higher labor costs due to additional training in preparation of retirements.

[7] Higher transportation costs due to increase in fuel in 2008.

Field Services O&M Costs	HELCO 2008 Application	HELCO 2008 Revised	HELCO 2008 Change	2004 Recorded	2005 Recorded	2006 Recorded	2007 Recorded	2008 Recorded
Labor Costs (BU, incl. overhead 421)	1,079.5	537.1	(542.4)	**414.5**	**484.4**	**467.4**	**552.3**	**537.1**
Labor Overhead 406, 422, 423		225.3	225.3	**127.0**	**185.0**	**227.8**	**246.5**	**225.3**
Non-Labor Costs (incl. materials & supplies, excl. Outside Services)	58.1	7.6	(50.5)	**8.0**	**8.0**	**6.3**	**9.9**	**7.6**
Transportation Costs	84.0	46.4	(37.6)	**63.3**	**45.9**	**47.7**	**41.7**	**46.4**
Outside Services	22.7	17.5	(5.2)	**14.8**	**31.0**	**21.7**	**24.8**	**17.5**
Total Field Services O&M Costs	1,244.4	833.9	(410.5)	627.6	754.3	770.9	875.1	833.9

NOTE: The Field Services O&M Costs used for the application is being revised utilizing the 2008 recorded costs as a more reasonable estimate.
The original costs included in the application utilized the Pillar files for 2008 budget, which needed to be allocated between field service work and customer service office work (primarily call center).

CA-IR-6

Ref: Quantifiable Benefits - Application and Exhibits 15 and 19.

a. If not already included in a different response, given the relatively nominal savings expected for meter reading, please explain why the Companies are not reflecting the elimination of the meter reading positions, the overhead associated with these positions, including, but not limited to supervisory expenses, and all other associated costs.
b. If not already included in a different response, please discuss whether the Companies have estimated the vehicle costs (e.g., depreciation, fuel, repairs, etc.) that will be avoided with the elimination of the need for manual meter reading. If so, please ensure that the Companies have provided documentation that illustrates the calculation of the savings associated with these expenses.

HECO Companies' Response:

a. The companies expressed the meter reader savings within the application as savings in expenditures (including overheads). The following costs were taken into account when calculating the meter reader benefits:

   - Labor Costs (BU, including overhead)
   - Labor Costs (merit, including overhead)
   - Non-Labor Costs (including materials & supplies, excluding. Outside Services)
   - Transportation Costs
   - Outside Services

   The application did not provide an estimated reduction of the meter reading positions. However, the Companies do anticipate a reduction in staffing as a result of the implementation of AMI. The reduction in estimated meter reading head count is provided in Attachment 1 to this response.

b. The Companies have estimated the avoided vehicle costs (e.g., depreciation, fuel, repairs, etc.) resulting from the reduction in the need for manual meter reading. The Companies'

CA-IR-2, Attachment 1, Section IX provides a detailed analysis for all meter reading benefits. In addition, CA-IR-2, Attachment 2, Section IX provides the detailed narrative explaining CA-IR-2, Attachment 1, Section IX.

Meter Reading Estimated Manning

HECO	[1] No-AMI	[2] With AMI
Meter Readers	32	6
Clerks	1	1
Supervisors	1	1

HELCO	No-AMI	With AMI
Meter Readers	10	2
Clerks	0	0
Supervisors	2	2

MECO	No-AMI	With AMI
Meter Readers	8	2
Clerks	0	0
Supervisors	0	0

[1] CA-IR-2, Attachment 1, Section IX.B.1
[2] CA-IR-2, Attachment 1, Section IX.C.5b

CA-IR-7

Ref: Application, page 8.

On page 8, the Companies indicate that "[t]he revenue requirement analysis should not be confused with a complete business case for installing the AMI platform, which would require quantification of the costs and benefits of the programs or activities . . ."

a. Please provide a copy of the "complete business case" that the Companies completed to justify the proposed project.
b. If the Companies did not conduct a complete business case, please discuss why not.
c. If not already discussed, please confirm that the Board of Directors approved the instant project.
    1. If not, please explain why Board of Director approval was not necessary.
d. If the Board of Directors approved the instant project, please provide a copy of the business case or applicable presentation that the Board of Directors relied upon to decide that the proposed project should be conducted.

<u>HECO Companies' Response:</u>

a. AMI refers to systems that measure, collect and analyze energy usage, from advanced devices such as electricity meters, gas meters, and/or water meters, through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications, customer associated systems and meter data management software.

The network between the measurement devices and business systems allows collection and distribution of information to customers, suppliers, utilities and service providers. This enables them to either participate in, or provide, demand response solutions, products and services. By providing information to customers, the system assists a change in energy usage from their normal consumption patterns, either in response to changes in price, or in response to incentives designed to encourage lower energy use at times of peak-demand periods or higher wholesale prices, or during periods of low operational systems reliability.

The proposed AMI project provides two way communications for both the utility and the customer. For the utility, communication from the meter permits the utility to cost-effectively collect time-based customer consumption information that will permit the utility to bill time-based rates such as time-of-use rates and dynamic pricing. Communication from the utility to the meter will provide operational benefits and enable cost-effective ratchet resets and start and stop service, for example. Communication from the utility to end-use controls can change the settings for and activate load interruptions under load management and dynamic pricing programs. Signals from the end-use controls can confirm that the settings were performed correctly and confirm that the controls operated as designed when activated.

The benefits of AMI can generally be broken down into four types: (1) operational benefits (e.g., meter reading savings and field service savings); (2) customer benefits (e.g., meter accuracy gains and energy theft reduction); (3) future capital expenditure reduction (e.g., net energy meters, time-of-use metering and general meter replacement due to failures); and (4) future systems benefits derived from programs that the AMI system supports or provides a platform for developing (e.g., customer service, demand response, distribution asset utilization and outage management), which give customers increased flexibility and satisfaction while empowering them to make wiser energy choices. The estimated operational benefits, customer benefits and future capital reduction are presented in the response to CA-IR-35, Attachment 1.

The costs of installing the AMI platform will be offset by certain direct, quantifiable benefits. Installation of the AMI platform, along with making usage feedback information available to customers, will also provide customer benefits that are not quantifiable at this time. For the customer, communications from the meter (indirectly through the utility system) can provide timely information about real-time consumption including the impact on electricity use from changes in behavior that the customer may take (e.g., turning off the lights, etc.). Communication from the customer to end-use controls on his premise can change customer-controllable options on utility sponsored remotely controlled thermostats, for example.

Energy efficiency and conservation behavior on the part of customers is likely to be reinforced if positive behaviors show results on a timely basis. The cost-effective collection of time-based information from customer meters made possible by smart AMI meters, and the subsequent placement of that information on the Internet for the customer to view, made possible by the meter data management system, provides more timely and informative feedback than a bill once a month. Thus, the energy savings from turning off the lights or electronic equipment can show up in a very timely basis, and positively reinforce and sustain that behavior in the future.

As indicated above, installation of the AMI platform will facilitate the ability to implement TOU rates on a much broader scale in the future. Time-of-use rates are rates that differ by periods of the day and signal to the customer when energy use is more expensive to provide than in other periods. Since energy is typically more expensive to provide during peak periods, time-of-use rates encourage the shifting of customer consumption from peak periods to off-peak periods. In order to bill time-of-use rates properly, time-based energy consumption information must be cost-effectively collected and delivered to the utility. Smart meters to collect the time-based consumption data and the meter data management system that serves as an intelligent repository for that data are part of the AMI project that facilitate the cost-effective collection and delivery of the information for billing.

In addition, installation of the AMI platform will enable the future implementation of dynamic response programs and smart grid initiatives. Neither the benefits nor the costs of these future initiatives have been evaluated in Hawaii at this time. For example, the assessment of the cost-effectiveness of a full scale dynamic pricing program would depend on the peak reductions that can be achieved and the cost of the program, neither of which is known at this time.

HECO has two existing DSM load management (demand response) programs, the Commercial and Industrial Direct Load Control ("CIDLC") and the Residential Direct Load Control ("RDLC") Programs, which reduce load through direct control of load control switches installed on customer loads. In return for allowing these load control switches to be installed, program participants are paid an incentive. These switches are activated when system frequency drops to predetermined levels and interrupt customer loads. (System frequency drops when aggregate customer demand is higher than the output that electricity generators on-line are able to provide.) If the amount of load curtailed restores the balance between customer load and the supply of generation, the system stabilizes. These switches can also be activated if HECO anticipates in advance that it will have difficulty meeting the demand. The switches are restored to their original state once the critical peak period is over.

The Company plans to implement and administer a Dynamic Pricing Pilot Program, and filed an application requesting the Commission's approval of this program on April 24, 2008 (Docket No. 2008-0074). The DPP Program is a demand response program that provides peak time customer incentives, or rebates ("PTR"). A PTR program provides monetary incentives to customers for every kilowatt-hour saved during the applicable time period. The objective of this pilot is to test the effect of a demand response program on a sample of residential customers for system reliability purposes. The dynamic pricing pilot is considered to be a demand-side load management program because incentives are paid to encourage customer curtailment of load through price incentives during critical peak periods when there is insufficient generation to meet a projected peak demand period (in a manner similar to the Company's RDLC and CIDLC Programs).

Under the DPP program central air-conditioning thermostats that can be remotely controlled by HECO are installed rather than load control switches. HECO would be able to raise the thermostat set point temperatures, and thereby, reduce the customer demand on the system. DPP Program participants are paid an incentive based on the amount of energy saved during the critical peak period.

These three demand response programs can be implemented with the existing one-way paging communication. However, the AMI project can facilitate these demand response programs by establishing two way communication between the utility and the load control devices (including the thermostat) to activate the devices or to change device settings (such as the thermostat set point temperature increase). The load control device will also be able to communicate back to the utility (something that the current paging system cannot do) to confirm the settings and confirm whether or not the device was activated as it was designed to do. This information is important to identify malfunctioning devices and to conduct comprehensive program evaluation, measurement, and verification.

The above programs effect load reductions in a single step, i.e., all devices are activated at the same time to achieve the maximum amount of load reduction in an effort to restore or maintain system frequency stability. Once the critical peak period is over, the devices are restored to their original state. However, these load control devices have the potential to be activated in a partial phased arrangement, and restored in a partial phased arrangement to follow changes over time in generation supply such as fluctuations in wind resources connected to the system grid. Thus, demand response resources have the potential to act as load following resources that can help to "regulate" frequency, or help prevent large frequency excursions.

For demand response resources to help regulate frequency, the software that activates the load control devices must be able to activate and restore the devices in coordination with changes in system frequency. Direct load control generally is not used to regulate frequency at this time, since this involves matching load and generation on a continuous basis. This is currently managed through the droop response of generators and the control of generator output through the Automatic Generator Control component of the Energy Management System.

The Company intends to explore the extent to which properly designed direct load control measures can assist in providing the substantial ancillary services that will be required to integrate substantial amounts of intermittent, fluctuating renewable electrical energy (such as that generated from wind farms) into its system. For example, one of the most important issues will be managing the system impacts (including frequency impacts) from large wind farms of sustained ramp down events that could occur when the wind drops. Such events could potentially be managed through a combination of resources such as increased spinning reserves, and on-site battery energy storage systems that slow the rate of the ramp down events, as well as direct load control resources, other load management resources, and distributed standby generation in the event the magnitude of the sustained ramp down exceeds the on-line reserves. See discussion of the Maui Electrical System Analysis and the Oahu Electrical System Analysis on pages 32 to 37 of Mr. Bruce Tamashiro's (HECO T-14) testimony within Docket No. 2008-0303 and the Company's response to CA-IR-84 of Docket No. 2008-0303. AMI would facilitate the acquisition of the additional load management resources as they develop.

Further, AMI communication and smart metering infrastructure can provide a foundation for the implementation of Smart Grid technology, which combines intelligent electronic devices (i.e., smart relays and distribution automation devices) and advanced applications that utilize timely data on customer loads and voltages through AMI and potential load reductions through demand response. It provides capabilities in monitoring, controlling, optimizing and automating the restoration of the electric power delivery system.

HECO contracted with KEMA Consulting to prepare a preliminary analysis of Advanced Metering. The deliverable item from this work was an April 5, 2007 power point Executive Briefing entitled the "Economics of Advanced Metering with Wireless Sensus/FlexNet Network." This document was very preliminary in nature and does not reflect the current state of financial analysis.

To date, HECO also has analyzed the potential direct costs and benefits of installing the AMI platform under a number of scenarios for various purposes, such as reviewing the potential impact on the amount and timing of the incremental capital the HECO Companies would have to raise to finance the installation of the AMI platform, and the "net" cost to customers of installing the AMI platform.

HECO developed a detailed financial analysis for the deployment of a fixed radio frequency AMI technology (called FlexNet) from Sensus Metering Systems at HECO, MECO, and HELCO and has provided it as Attachment 1 to the reponse to CA-IR-2. HECO also developed and submitted a detailed narrative explaining the financial as Attachment 2 to the reponse to CA-IR-2.

The HECO Companies provided an updated presentation of the Companies' net incremental revenue requirement for the AMI project in Attachment 3 to the response to CA-IR-35. The HECO Companies provided an updated estimated rate of impact for the AMI surcharge in Attachment 2 to the response to CA-IR-35.

b. The Companies have provided significant business case information above. HECO objects to providing preliminary analyses, incorporating illustrative and/or outdated information and assumptions, on the grounds that such analyses are not relevant to the issues in this proceeding.

c. The AMI project was identified as a major project that was included in the 2009-2013 capital budget that was presented to the Board of Directors during the budget review presentations at its November 17, 2008, December 8, 2008, and January 26, 2009 meetings. At the January 26, 2009 meeting, the Board of Directors approved the 2009-

2013 capital expenditures program which included the AMI project. On March 4, 2009, the Companies submitted the "Hawaiian Electric 2009 Capital Expenditures Budget" to the Commission. Page 3 of the attachment to this budget document identifies the AMI Project and the 2009-2013 budget that was approved by the Board of Directors ("BOD").

d. Without waiving any of the objections stated below, in response to this information request, Attachment 1 hereto provides the portion of the presentation related to the AMI Project that was provided to the BOD for its December 8, 2008 meeting.

HECO respectfully objects to providing the "applicable presentation that the Board of Directors relied upon to decide that the proposed project should be conducted. HECO further objects to disclosing documents that reveal internal deliberations regarding the AMI Project. Requiring that this information be subject to review by parties in a regulatory proceeding would have a "chilling" effect on the self-analysis process, and would inhibit robust and candid internal dialogue of this nature in the future.
This information request fails to balance the need for the information against HECO's need to manage. By analogy, for example, the Federal Freedom of Information Act ("FFIA"), codified at 5 U.S.C. §552, and the Uniform Information Practices Act (Modified), codified at H.R.S. Ch. 92F, contain broad disclosure requirements based on the public's interest in open government. However, the broad policy in favor of disclosure still allows for exceptions that are intended to permit the efficient and effective functioning of government by protecting the internal deliberative process. *See generally, Pennsylvania Public Utility Commission v. West Penn Power Company*, 73 PA PUC 122

(July 20, 1990), West Law Slip Op ("deliberative process privilege" recognized by the Pennsylvania Public Utility Commission with respect to its own internal staff reports). The Companies anticipate providing the BOD with an update on the AMI Project in August 2009.

Hawaiian Electric Company, Inc.

Hawaiian Electric Company
Preliminary Budget
2009-2013
December 8, 2008 Board Meeting

HEI

CA-IR-7
DOCKET NO. 2008-0303
ATTACHMENT 1
PAGE 1 OF 3

Hawaiian Electric Company, Inc.

HECO Capital Expenditures

(HCEI creates the opportunity for accelerated recovery mechanisms for certain projects)

$ in millions

	2009	2010	2011	2012	2013	5 yr total
"Core" Projects						
[redacted]						
Major Projects not included above*						
[redacted]						
Advanced Metering Infrastructure*	0.0	0.4	11.7	11.7	11.9	35.7
[redacted]						
Total	**205.3**	**158.9**	**215.9**	**283.3**	**254.0**	**1,117.4**

*See Apendix A for detailed project information (excluding Other Unidentified DG)

Excludes comprehensive asset management plan

HEI

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ATTACHMENT 1
PAGE 2 OF 3

Hawaiian Electric Company, Inc.

Advanced Metering Infrastructure

- AMI is a critical component of a number of key aspects of the Clean Energy Initiative
  - AMI will help customers manage their energy use more effectively
- Filed PUC application – December 1, 2008
- Meter Deployment:
  - HECO (2011-2013), MECO (2014), and HELCO (2015)
- Install approximately 451K AMI meters at HECO (293K), MECO (66K), and HELCO (92K).
- Project Costs (2008-2015 per PUC Application):
  - HECO \$71M, MECO \$19M, HELCO \$22M, Total \$112M
- Special Accounting Treatment: PUC approval required for accelerated recovery of new and existing meter costs
- REI Surcharge Recovery: PUC approval required for recovery of net costs (i.e., costs less labor savings)

HEI

CA-IR-7
DOCKET NO. 2008-0303
ATTACHMENT 1
PAGE 3 OF 3

CA-IR-8

Ref: Application - Project Timeline.

a. Please provide a project timeline for the AMI project that identifies all major milestones and critical paths.
b. If not already identified in the timeline provided related to the AMI, please explain and discuss the timing of the CIS project and how the delay in the successful in-service date of the CIS will affect, if at all, AMI project.

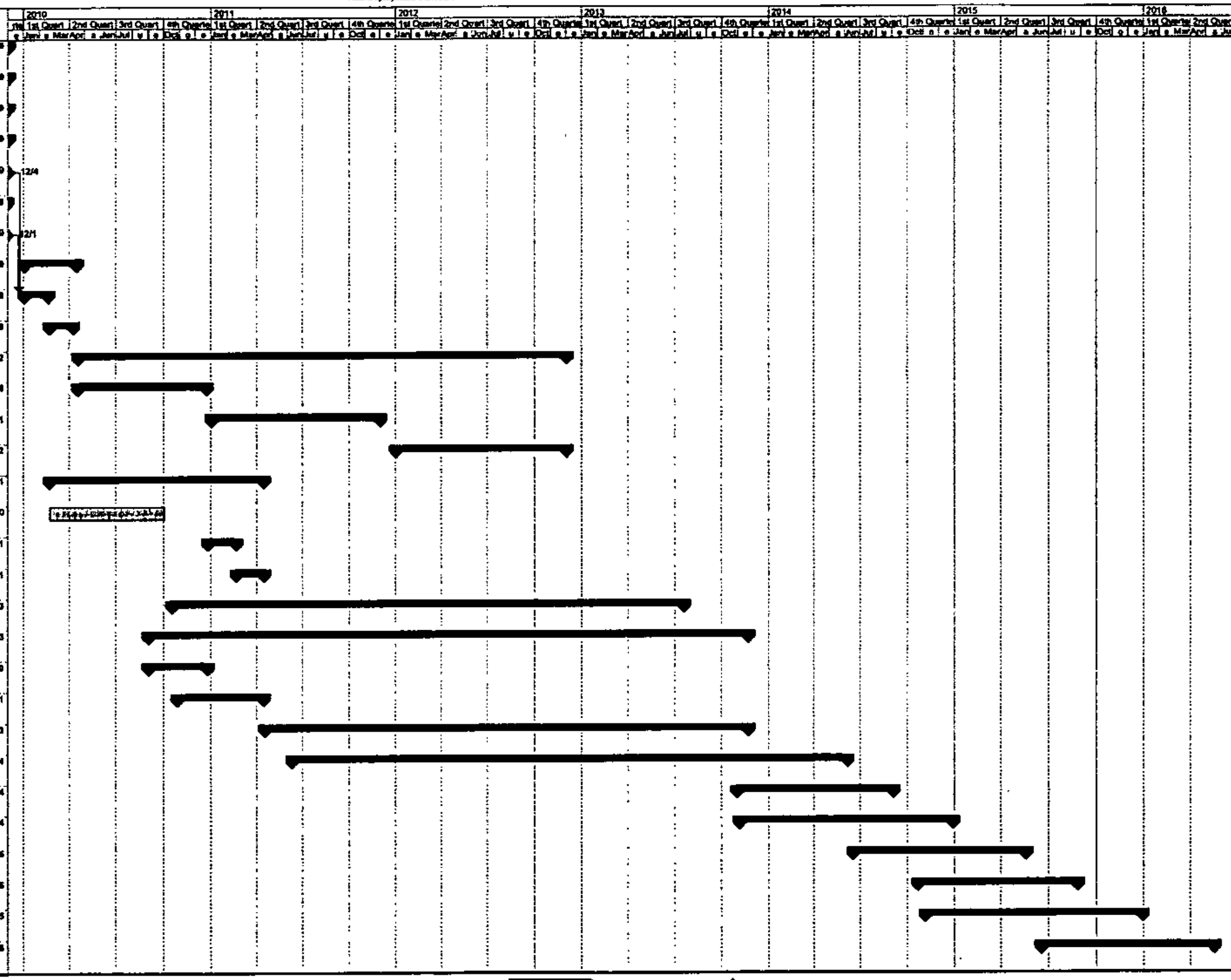
HECO Companies' Response:

a. The anticipated AMI project schedule is provided as Attachment 1 hereto. This schedule assumes Commission approval by December 1, 2009. If Commission approval is delayed, the project schedule will be delayed accordingly.

b. Exhibit 18 to the AMI Application contains the current estimated schedule of the AMI Project and the two phases in which integration of the Companies' Customer Information System ("CIS") and Sensus' Regional Network Interface ("RNI") are planned to be implemented. The first phase of integration is currently planned to begin in 2010 and be completed in the fourth quarter of the same year. As noted in the Company's response to CA-IR-323, filed in Docket Number 2008-0083, the Company was in the process of developing a revised workplan and go-live schedule with the CIS vendor. At present, the Company and vendor have not completed a workplan, nor has an in-service date been forecast. The AMI project team is in contact with the CIS project team and monitoring progress on the revision to the CIS workplan and schedule. The Company is working to develop alternatives to support the alignment of the AMI and CIS solutions.

AMI Deployment Schedule

ID	Task Name	Start	Finish
19	Meter Data Management Systems Consultants	Mon 9/10/07	Fri 12/4/09
39	SI/MDMS Selection	Tue 1/6/09	Fri 12/4/09
40	Select SI/MDMS Preferred Vendor	Tue 1/6/09	Fri 12/4/09
62	Complete SI/MDMS Contract	Fri 9/25/09	Fri 12/4/09
68	SI/MDMS Contract Execution	Fri 12/4/09	Fri 12/4/09
149	Regulatory Process (HECO/MECO/HELCO)	Mon 9/10/07	Tue 12/1/09
209	PUC approval	Tue 12/1/09	Tue 12/1/09
470	MDMS Requirements & Design	Mon 1/4/10	Fri 4/16/10
471	Develop detailed requirement specifications	Mon 1/4/10	Fri 2/19/10
480	Develop detailed system design	Mon 2/22/10	Fri 4/9/10
488	MDMS Development, Deployment, Testing	Mon 4/19/10	Mon 12/3/12
490	MDMS Implementation - Phase 1 (CIS Integrations)	Mon 4/19/10	Fri 12/24/10
495	MDMS Implementation - Phase 2 (Other Integrations	Mon 1/3/11	Fri 12/2/11
501	MDMS Implementation - Phase 3 (MECO/HELCO Sys	Tue 1/3/12	Mon 12/3/12
507	HECO RNI Installation	Mon 2/22/10	Fri 4/15/11
508	Install HECO RNI	Mon 2/22/10	Mon 10/4/10
509	RNI FAT	Mon 12/27/10	Mon 2/21/11
512	RNI SAT	Mon 2/21/11	Fri 4/15/11
515	HECO Network Deployment	Mon 10/18/10	Fri 7/19/13
524	HECO Meter Full Deployment	Fri 9/3/10	Fri 11/22/13
525	FAT	Fri 9/3/10	Mon 12/27/10
530	SAT - End-to-End MXS/RNI/MDMS/CIS	Fri 10/22/10	Fri 4/15/11
536	Meter Full Deployment	Mon 4/18/11	Fri 11/22/13
540	HECO Employee Redeployment	Fri 6/10/11	Fri 6/6/14
543	MECO Network Deployment	Fri 11/1/13	Thu 9/4/14
548	MECO Meter Full Deployment	Wed 11/6/13	Tue 12/30/14
559	MECO Employee Redeployment	Tue 6/17/14	Tue 6/16/15
562	HELCO Network Deployment	Thu 10/23/14	Wed 8/26/15
567	HELCO Meter Full Deployment	Thu 11/6/14	Wed 12/30/15
578	HELCO Employee Redeployment	Wed 6/17/15	Wed 5/18/16



Project: HECO AMI
Date: Thu 5/14/09

Task | Split | Milestone | Project Summary | External Milestone
Project Guide: Critical Task | Progress | Summary | External Tasks | Deadline

CA-IR-9

Ref: Application – CIS.

a. If not already discussed, please identify the most current estimate of when the CIS project will be successfully completed and placed into service.
b. Based on Exhibit 9, page 2, there are certain features or functions that definitely rely on the CIS. Please confirm that without the CIS, these features or functions will not be available.
c. Please quantify the impacts on the projected costs and savings that are applicable to the proposed AMI project that are affected by the delay in the CIS. Please provide the assumptions and calculations used by the Companies to determine the response.

HECO Companies' Response:

a. At present, the Company and vendor have not completed a revised work plan, nor has an in-service date for the Customer Information System ("CIS") been estimated.

b. All AMI features defined on Exhibit 9, page 2 can be achieved with or without the new CIS. At the time that this Meter Data Management System ("MDMS") architecture diagram was generated, it was assumed that the new CIS would be the Peace (as noted on the diagram) and that it would go live in advance of the MDMS going live. If the new CIS is not available, the interaction and operation of the advanced AMI functionality will have to be performed within the MDMS. In this scenario, the MDMS would be interfaced to the legacy CIS (CB-ACCESS) to support basic billing. The interface could not support complex billing requirements such as time-of-use ("TOU"). In this scenario, the HECO Companies would likely request Commission approval for TOU meter limitations as noted in the AMI application, Exhibit 25, page 2 (Limitations on Participation in Time-of-Use Rate Options). The Company is working to develop alternatives to support the alignment of the AMI and CIS solutions.

c. Due to the basic level of interfacing, there would be limitations in the timing and quantity of data exchange. HECO personnel would have to perform operations in both the legacy CIS and the MDMS to complete their business processes. This would result in in-efficiencies in their work processes. HECO currently has no specific information to quantify any costs related to these in-efficiencies.

CA-IR-10

Ref: Application - Project Timeline.

It appears that the AMI project timeline has the network installed on a linear schedule with the installation for each company occurring sequentially, rather than concurrently. Similarly, the meter installation is also scheduled sequentially.

a. If not already discussed elsewhere, please explain how any "first-come, first-served" requests will be accommodated.
    1. Please provide a detailed discussion of the education and/or advertising that will be conducted by the Companies to inform customers that these meters are available and on a "first-come, first-served" basis. Please provide copies of any developed media that is expected to be used for these purposes.
        (a) If not already discussed, please discuss the timing in relation to the project timeline of the Companies planned informational campaign to educate the customers about the meters and the availability of these meters.
        (b) If not already addressed, please discuss whether any such informational campaign should follow the implementation of certain key components of the project. If so, please include in the Companies' response an identification of those project components that are deemed critical to allowing the Companies and the customers to receive the highest level of benefits.
    2. Assuming that these meters are installed as requested by the consumer, please confirm that, if the AMI network, other supporting infrastructure, and tariff plans are not in place, the customers and the Companies will not be able to receive the full benefits of the AMI meters since the meters will not be used to the full extent of its capabilities.
b. Please explain why HECO will have its AMI network installation occur first (November 2010 through August 2013), MECO's installation next (November 2013 through September 2014), and HELCO's installation last (October 2014 through August 2015).

<u>HECO Companies' Response:</u>

a. Upon the approval of the Commission, the Companies will exert reasonable efforts to fulfill all customer requests for advanced meters. In cases where advanced meters are installed prior to the installation of the AMI network, the meters will be read manually until AMI network coverage is established.

1. The detailed plan for the advertising and/or training of the customers has not been developed; however, they will be developed shortly after the AMI Project is approved by the Commission. The Companies will support the State in its efforts to educate the public about their energy usage, as provided for in Section 36 (Telling the Energy Story) of the October 20, 2008 *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs and the Hawaiian Electric Companies*, which provides in relevant part:

> *The State will take the lead in educating its citizens and businesses on the value of the Hawaii Clean Energy Initiatives.*
>
> *The State with inputs from the utilities, and other stakeholders, will develop a common set of messages about the importance, rationale for and scope of the Hawaii Clean Energy Initiative.*

   (a) The Companies intend to use a variety of media to educate and inform the public, and include information on the Companies' website, at the Companies' community outreach events and in the Companies' bill inserts, as well as in releases provided to the media.

   (b) See the response to 1. and 1. (a) above.

2. Customers with AMI meters and AMI network coverage will be able to receive each of the quantifiable benefits presented in the application once the AMI network, other supporting infrastructure, and tariff plans are in place.

b. The timescale was established in an effort to plan an achievable implementation without overextending the Companies' limited resources. Many other utilities are also implementing AMI systems, which is making it difficult for Companies to obtain resources. Sequential implementation allows the Companies to leverage their manpower resources to support the implementation at each respective company. HECO was selected to proceed first since it has the largest customer base, largest resource pool and the most experience with AMI systems (as a result of its current pilot activities). Additionally, the Meter Data Management System will be located at HECO, which facilitates overall AMI system commissioning. MECO was selected to proceed prior to HELCO in order to take advantage of the ongoing Maui Smart Grid Pilot, which includes AMI.

CA-IR-11

Ref: Application, page 16.

In footnote 16, page 16, the Companies indicate that the "islands of Molokai and Lanai will be examined after AMI system deployments are completed on Oahu, Maui, and Hawaii."

a. Please provide a detailed discussion of what exactly will be examined in order to determine when, or if, the customers on the islands of Molokai and Lanai will be able to have the opportunity to experience the purported benefits associated with the AMI network, meters, etc.
b. Please discuss whether the customers on Lanai and Molokai will have to contribute to the cost of the AMI project if they are not able to receive any of the purported benefits associated with the project.
c. Please provide a copy of any analyses, business plan, or other report conducted by or on behalf of the Companies to determine that the installation of the AMI network, meters and other equipment may not be cost effective for the islands of Molokai and Lanai.
    1. If no such analysis or study has been conducted, please explain why the Companies decided that a further analysis should be conducted before rolling out AMI infrastructure to Molokai and Lanai.
    2. If not already discussed elsewhere, please confirm that no such analysis, study, or any other kind of report has been conducted to substantiate a claim that the proposed AMI project will be cost effective for any of the islands.

<u>HECO Companies' Response:</u>

a. As stated in section III.C.2 (AMI Network) of the instant Application, one of the major benefits of the Sensus FlexNet System is that a large area can be covered with each Tower Gateway BaseStation ("TGB"). However, the high cost of TGB installation and operation is prohibitive unless a minimum number of meters (15,000) utilize each TGB. The Companies are evaluating the capability of utilizing smaller scale collection devices such as a FRP (described in the Application, Exhibit 11, pages 8 through 10) to extend the geographic coverage of the AMI network. AMI mesh technologies (see Attachment 1 hereto) may provide better options for small scale coverage and are being assessed by the

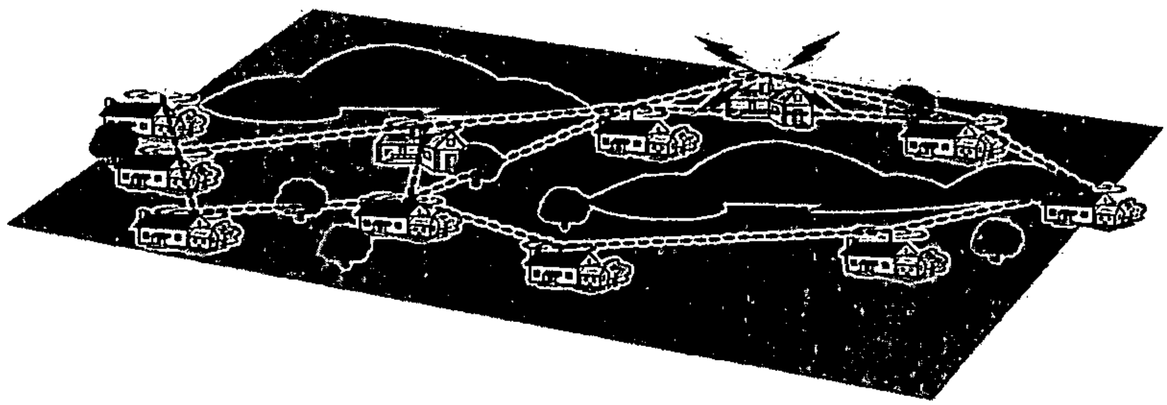
Companies. The Companies have not yet developed an AMI plan for customers on the islands of Molokai and Lanai.

b. The customers on Lanai and Molokai are not being requested to contribute to any of the AMI project costs under the instant Application.

c. Analyses, business plans, or other reports have not been completed for the islands of Molokai and Lanai.

AMI Mesh Technologies

One grouping of AMI technology is termed "mesh" to denote radio frequency ("RF") networks that use network nodes and the endpoints themselves to create a woven communication network where messages from or to an endpoint do not take a direct path between the endpoint and the collector network node. The intermediate network nodes (i.e. network or meter elements) act as repeaters or routers that hand off the messages so that they reach their intended destination.



The mesh design provides for improved system performance by providing multiple communication paths for any individual meter's message traffic to use. In the event that there is a temporary or permanent obstruction or interference that renders a particular path unusable, or if system congestion along a particular path becomes excessive, the mesh will adjust and establish a new preferred communication path to be used.

Some of the particular characteristics of the Mesh networks include:

- The LAN network is comprised of the meter endpoints and repeaters/routers.
- The LAN forwards messages to WAN access points by a predefined routing protocol.
- Mesh systems use utility poles, street lights or communications towers to mount WAN access points or use meters to provide access points.
- WAN access point antenna elevation is not as critical a factor in system performance, thereby improving flexibility in siting these devices.
- Mesh networks reduce line of sight problems found in star hierarchical types of RF systems.
- The inherent design and operation of mesh networks provides some basic overlapping of coverage; however, actual disaster recovery capabilities therein are dependent on the sophistication of the head end system disaster recovery implementation.

- Mesh networks generally require installation of more intermediate network devices as compared to Star networks.
- Mesh networks typically operate in the unlicensed radio spectrum; however, the nature of the proprietary frequency hopping algorithms used by Mesh systems provides some safeguards against potential interference from competing radio traffic.

CA-IR-12

Ref: Application.

In various places in the application (see, e.g., page 17), the Companies indicate that the AMI system will possess the ability to acquire interval data at 15-minute or 1-hour periods.

a. Please discuss whether there is any cost differential in any of the components to the AMI project in order to allow the acquisition of interval data at 15-minute, 1-hour or other interval periods.
b. If so, please discuss whether the Companies have conducted any analyses to determine whether it might be more cost effective to have the system acquire data at a single interval period, say 1-hour. If so, please provide a copy of that analysis.
c. Please discuss whether the Companies have conducted any type of analysis that evaluates whether differing levels of benefits are achievable at different data acquisition intervals. If so, please provide a copy of the analysis, study or report and copies of any supporting documentation that quantifies the differing levels of benefits that might be achievable through different data acquisition intervals.

<u>HECO Companies' Response:</u>

a. There is no direct operational cost differential in any of the components to acquire 15-minute, 1-hour or other interval periods. However, there is a difference in the initial cost for many of the components for a higher frequency of data acquisition and delivery. The AMI system design factored in the Companies' business needs. The system will be configured to capture 1-hour interval data for the majority of the Companies' meters. Only the commercial & industrial meters and other special study meters (Class Load, etc.) will be configured to capture 15-minute interval data. This is consistent with the Companies' current practice for interval data collection. The sampling intervals can be changed via over-the-air programming as required. The Inbound Channel Data Delivery and TGB Design Requirements for the AMI Network are provided as Attachment 1 hereto.

b. No such analysis has been done.

c. Shorter data intervals are preferred; however, shorter intervals generate larger amounts of data. For commercial and industrial customers, 15-minute interval data has been the standard and the Companies believe this is a reasonable interval to use, given the investment being proposed in AMI. For residential customers, the Companies relaxed the data interval requirement by a factor of four (1 hour versus 15 minutes) in order to efficiently utilize the available bandwidth (data carrying capacity) of the AMI network. Since residential customers comprise the largest segment of the meter population in terms of meter count, an increase in data capture by a factor of four would place an undue burden on the AMI network, which would also impact the Companies' ability to send 2-way commands to meters and other devices in the future.

Although the choice of interval is important, the Companies have not specifically conducted any type of analysis that evaluates whether differing levels of benefits are achievable at different data acquisition intervals. However, the AMI meters can be remotely programmed for intervals as short as one minute; therefore, the initial choice of interval does not necessarily preclude changes being made in the future. The Company acknowledges that there will be finite limits to data rates due to the current bandwidth limitations of the proposed Sensus AMI network.

HECO FlexNet Inbound Channel Data Delivery & TGB Design Requirements

Read Interval in Minutes (5, 15, 60)	Resolution in Watthours (1, 10, 100, 1000)	Meter Count	Meter Count with Growth	1-Minute TX Interval	2.5-Minute TX Interval	10-Minute TX Interval	30-Minute TX Interval	45-Minute TX Interval	60-Minute TX Interval	1.5-Hour TX Interval	2-Hour TX Interval	4-Hour TX Interval	Normalized Message Load
60	1000	284,000	308,140									308,140	308,140
15	10	9,700	10,525					10,525					56,133
15	10	0	0					0					0
60	1000	1,000	1,085									1,085	1,085
60	1000	0	0									0	0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
60	10	0	0			0							0
15	10	0	0		0								0
5	10	200	217	217									52,080
Totals		**294,900**	**319,967**	**217**	**0**	**0**	**0**	**10,525**	**0**	**0**	**0**	**309,225**	**417,438**

Total TGBs in this analysis	15
# of Whole KWH Resolution Meters	309,225
# of 100 Watt-hour Resolution Meters	0
# of 10 Watt-hour Resolution Meters	10,742
# of 1 Watt-hour Resolution Meters	0
Total Meters	**319,967**
# of 1 minute TX Meters	217
# of 2.5 minute TX Meters	0
# of 10 minute TX Meters	0
# of 30 minute TX, 1 Hour History Meters	0
# of 30 minute TX, 1.33 Hour History Meters	0
# of 30 minute TX, 1.42 Hour History Meters	0
# of 30 minute TX, 1.67 - 10.00 (5.00) Hour History Meters	0
# of 30 minute TX, 2.75 Hour History Meters	0
# of 45 minute TX, 3.5 Hour History Meters	10,525
# of 45 minute TX, 3.75 Hour History Meters	0
# of 60 minute TX, 5 - 30 Hour (15) History Meters	0
# of 1.5 hour TX, 10 Hour History Meters	0
# of 2 hour TX, 12 Hour History Meters	0
# of 2 hour TX, 13 Hour History Meters	0
# of 4 hour TX, 20 Hour - 5 Day (3.5 Day) History Meters	309,225
Total Meters	**319,967**
Additional load due to Normalized Message Load	**30.46%**

Notes:

HECO FlexNet Outbound Channel Daily Requirements

FlexNet Channel Use	Quantity Per Day	Channel Time in hours (2)
Move-In/Move-out Reads	160	0.01
Demand Reads	120	0.00
Remote Disconnect/Reconnect	100	0.00
False Outage Check	100	0.00
Load Control	70,000	2.59
Demand Response / Pricing Information	5,000	0.19
Interval Data Retrieval - 1 Channel (3)	0	0.00
Interval Data Retrieval - 2 Channel (3)	9,700	8.98
Interval Data Retrieval - 3 Channel (3)	0	0.00
Distribution Automation Control	100	0.00
Prepayment Metering Information	0	0.00
Firmware Updates and other System Administration (1)	see note 1	see note 1
Buffer	see note 2	see note 2
Total	**85,280**	**11.78**

Notes:

(1) In various scenarios this is a 2 to 5 day one time process (assuming that only 25% of the channel capacity is used for that function, and it runs as the lowest priority batch job and therefore transparent).

(2) All channel uses have been illustrated with 50% a reserve. All calculations based on meters within a 15 TGB coverage area.

(3) Interval Data Retrieval requires multiple messages to get 24 hours of data.
1 Channel Retrieval requires one header message and three messages for each 4-hour block for a total of 19 messages per 24 hours
2 Channel Retrieval requires one header message and four messages for each 4-hour block for a total of 25 messages per 24 hours
3 Channel Retrieval requires one header message and five messages for each 4-hour block for a total of 31 messages per 24 hours

HELCO FlexNet Outbound Channel Daily Requirements

FlexNet Channel Use	Quantity Per Day	Channel Time in hours (2)
Move-In/Move-out Reads	160	0.01
Demand Reads	120	0.01
Remote Disconnect/Reconnect	100	0.01
False Outage Check	100	0.01
Load Control	5,000	0.40
Demand Response / Pricing Information	4,000	0.32
Interval Data Retrieval - 1 Channel (3)	0	0.00
Interval Data Retrieval - 2 Channel (3)	500	0.99
Interval Data Retrieval - 3 Channel (3)	0	0.00
Distribution Automation Control	100	0.01
Prepayment Metering Information	0	0.00
Firmware Updates and other System Administration (1)	see note 1	see note 1
Buffer	see note 2	see note 2
Total	**10,080**	**1.75**

Notes:

(1) In various scenarios this is a 2 to 5 day one time process (assuming that only 25% of the channel capacity is used for that function, and it runs as the lowest priority batch job and therefore transparent).

(2) All channel uses have been illustrated with 50% a reserve. All calculations based on meters within a 7 TGB coverage area.

(3) Interval Data Retrieval requires multiple messages to get 24 hours of data.
1 Channel Retrieval requires one header message and three messages for each 4-hour block for a total of 19 messages per 24 hours
2 Channel Retrieval requires one header message and four messages for each 4-hour block for a total of 25 messages per 24 hours
3 Channel Retrieval requires one header message and five messages for each 4-hour block for a total of 31 messages per 24 hours

HELCO FlexNet Inbound Channel Data Delivery & TGB Design Requirements

Read Interval in Minutes (5, 15, 60)	Resolution in Watthours (1, 10, 100, 1000)	Meter Count	Meter Count with Growth	1-Minute TX Interval	2.5-Minute TX Interval	10-Minute TX Interval	30-Minute TX Interval	45-Minute TX Interval	60-Minute TX Interval	1.5-Hour TX Interval	2-Hour TX Interval	4-Hour TX Interval	Normalized Message Load
60	1000	74,000	91,020									91,020	91,020
15	10	4,500	5,535					5,535					29,520
15	10	4,500	5,535					5,535					29,520
15	10	7,000	8,610					8,610					45,920
60	1000		0									0	0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
60	10	0	0			0							0
15	10	0	0		0								0
5	10	200	246	246									59,040
Totals		**90,200**	**110,946**	**246**	**0**	**0**	**0**	**19,680**	**0**	**0**	**0**	**91,020**	**255,020**

Total TGBs in this analysis	7
# of Whole KWH Resolution Meters	91,020
# of 100 Watt-hour Resolution Meters	0
# of 10 Watt-hour Resolution Meters	19,926
# of 1 Watt-hour Resolution Meters	0
Total Meters	**110,946**
# of 1 minute TX Meters	246
# of 2.5 minute TX Meters	0
# of 10 minute TX Meters	0
# of 30 minute TX, 1 Hour History Meters	0
# of 30 minute TX, 1.33 Hour History Meters	0
# of 30 minute TX, 1.42 Hour History Meters	0
# of 30 minute TX, 1.67 - 10.00 (5.00) Hour History Meters	0
# of 30 minute TX, 2.75 Hour History Meters	0
# of 45 minute TX, 3.5 Hour History Meters	19,680
# of 45 minute TX, 3.75 Hour History Meters	0
# of 60 minute TX, 5 - 30 Hour (15) History Meters	0
# of 1.5 hour TX, 10 Hour History Meters	0
# of 2 hour TX, 12 Hour History Meters	0
# of 2 hour TX, 13 Hour History Meters	0
# of 4 hour TX, 20 Hour - 5 Day (3.5 Day) History Meters	91,020
Total Meters	**110,946**
Additional load due to Normalized Message Load	**129.86%**

Notes:

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MECO FlexNet Outbound Channel Daily Requirements

FlexNet Channel Use	Quantity Per Day	Channel Time in hours (2)
Move-In/Move-out Reads	160	0.03
Demand Reads	120	0.02
Remote Disconnect/Reconnect	100	0.02
False Outage Check	100	0.02
Load Control	1,000	0.19
Demand Response / Pricing Information	2,000	0.37
Interval Data Retrieval - 1 Channel (3)	0	0.00
Interval Data Retrieval - 2 Channel (3)	0	0.00
Interval Data Retrieval - 3 Channel (3)	0	0.00
Distribution Automation Control	100	0.02
Prepayment Metering Information	0	0.00
Firmware Updates and other System Administration (1)	see note 1	see note 1
Buffer	see note 2	see note 2
Total	**3,580**	**0.66**

Notes:

(1) In various scenarios this is a 2 to 5 day one time process (assuming that only 25% of the channel capacity is used for that function, and it runs as the lowest priority batch job and therefore transparent).

(2) All channel uses have been illustrated with 50% a reserve. All calculations based on meters within a 3 TGB coverage area.

(3) Interval Data Retrieval requires multiple messages to get 24 hours of data.
1 Channel Retrieval requires one header message and three messages for each 4-hour block for a total of 19 messages per 24 hours
2 Channel Retrieval requires one header message and four messages for each 4-hour block for a total of 25 messages per 24 hours
3 Channel Retrieval requires one header message and five messages for each 4-hour block for a total of 31 messages per 24 hours

MECO FlexNet Inbound Channel Data Delivery & TGB Design Requirements

Read Interval in Minutes (5, 15, 60)	Resolution in Watthours (1, 10, 100, 1000)	Meter Count	Meter Count with Growth	1-Minute TX Interval	2.5-Minute TX Interval	10-Minute TX Interval	30-Minute TX Interval	45-Minute TX Interval	60-Minute TX Interval	1.5-Hour TX Interval	2-Hour TX Interval	4-Hour TX Interval	Normalized Message Load
60	1000	64,000	75,520									75,520	75,520
15	10	2,400	2,832					2,832					15,104
15	10	2,400	2,832					2,832					15,104
15	10	5,000	5,900					5,900					31,467
60	1000		0									0	0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
5	100		0				0						0
60	10	0	0			0							0
15	10	0	0		0								0
5	10	0	0	0									0
Totals		**73,800**	**87,084**	**0**	**0**	**0**	**0**	**11,564**	**0**	**0**	**0**	**75,520**	**137,195**

Total TGBs in this analysis	3
# of Whole KWH Resolution Meters	75,520
# of 100 Watt-hour Resolution Meters	0
# of 10 Watt-hour Resolution Meters	11,564
# of 1 Watt-hour Resolution Meters	0
Total Meters	**87,084**
# of 1 minute TX Meters	0
# of 2.5 minute TX Meters	0
# of 10 minute TX Meters	0
# of 30 minute TX, 1 Hour History Meters	0
# of 30 minute TX, 1.33 Hour History Meters	0
# of 30 minute TX, 1.42 Hour History Meters	0
# of 30 minute TX, 1.67 - 10.00 (5.00) Hour History Meters	0
# of 30 minute TX, 2.75 Hour History Meters	0
# of 45 minute TX, 3.5 Hour History Meters	11,564
# of 45 minute TX, 3.75 Hour History Meters	0
# of 60 minute TX, 5 - 30 Hour (15) History Meters	0
# of 1.5 hour TX, 10 Hour History Meters	0
# of 2 hour TX, 12 Hour History Meters	0
# of 2 hour TX, 13 Hour History Meters	*0*
# of 4 hour TX, 20 Hour - 5 Day (3.5 Day) History Meters	75,520
Total Meters	**87,084**
Additional load due to Normalized Message Load	***57.54%***

Notes:

CA-IR-13

Ref: Enhanced Outage and Restoration Reporting.

The Companies assert that the AMI system will provide "the ability to improve distribution system operations through enhanced outage and restoration reporting." (application, page 17).

a. As part of HECO's justification for the outage management system ("OMS"), it indicated that the OMS would provide the ability to report on information that would be useful in identifying, troubleshooting and facilitating the restoration of power. Please provide a detailed discussion of how the capabilities of the OMS and the capabilities of the AMI system differ in terms of "enhanced outage and restoration reporting."
b. Please provide a detailed discussion of how the capabilities of the OMS and AMI projects will provide additional synergies that will exceed the already existing capabilities of the OMS.
    1. Please itemize each of the enhanced capabilities that the interfaced OMS/AMI systems will be able to provide and provide a detailed discussion of each capability.
    2. For each of the enhanced capabilities, please provide the estimated impact on the following:
        (a) Troubleshooting and restoration abilities;
        (b) Outage identification; and
        (c) Reporting abilities.
    3. For each of the enhanced capabilities, please provide the estimated impact on operating and maintenance expenses.
        (a) Please provide copies of the workpapers used to determine the estimated increase in O&M costs to realize the possible synergies.
        (b) Please provide copies of the workpapers used to determine the estimated decrease in O&M costs that will be realized as a result of the synergies.
c. On page 25, the Companies assert that support for the OMS "will be addressed" in the future. Please explain why the system that the Companies picked does not have OMS support "out of the box" and that additional capital investment in the future is required to obtain the necessary support so that the OMS and AMI projects can properly interface.
d. If not already addressed, please confirm that the proposed AMI system will be able to interface with existing OMS without significant and costly modifications to either system (i.e., OMS and AMI). Please provide vendor documentation from the applicable vendors that substantiate the Companies' response.

<u>HECO Companies' Response:</u>

a. The OMS tracks, records and reports metrics on all phases of an outage. An AMI system does not reduce any capability of an OMS system. Rather, an AMI system enhances the capability of the OMS by providing quicker and more accurate information delivery and access.

b. A discussion of how the capabilities of the OMS and AMI projects could provide additional synergies that will exceed the present capabilities of the OMS is provided below, and in Attachments 1 through 3 hereto.

1. With respect to the enhanced capabilities that the interfaced OMS/AMI systems will be able to provide, please refer to Attachments 1 through 3 to this response.

2. With respect to the enhanced capabilities, the companies have not yet quantified the estimated impact of troubleshooting and restoration abilities; outage identification; or reporting abilities.

3. With respect to the enhanced capabilities, the Companies have not yet quantified the estimated impact on operating and maintenance expenses. Therefore, the requested workpapers are not available.

c. The Sensus FlexNet System is capable of supporting the OMS. The detailed requirements for Companies' Meter Data Management System ("MDMS") will be developed in 2009, it is anticipated that the selected MDMS will be capable of OMS support. However, the Sensus FlexNet System and the MDMS software products continue to evolve and current OMS support is limited. Custom interfaces will be required to fully achieve the desired AMI/OMS synergy. HECO's current OMS version is not fully AMI compliant; therefore, an OMS upgrade may be required to fully achieve the potential AMI/OMS benefits. Further evaluation is required to fully quantify the costs, benefits and risks associated with the AMI system's support of the OMS.

d. As stated above, further evaluation is required to fully quantify the costs, benefits and risks. Attachment 3 to this response shows that PEPCO has successfully integrated its AMI System. PEPCO and HECO use the same Oracle OMS product.

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AMI and OMS, Together - Finally!!! - By Ed Malemezian
Daily IssueAlert
10/16/2006

Free
The dream is now being realized. Utilities are finally reporting resounding success unlocking benefits that Advanced Metering Infrastructure (AMI) systems provide to their Outage Management (OM) processes. The results include reduced outage times, improved service reliability, and increased customer satisfaction, reaffirming their decision to implement AMI.

As expected, AMR to support meter reading generally has been a utility's first priority. After all, "the bills need to go out," and so they do. With that under their belts, utilities are now seriously looking at the other types of benefits enabled by a working AMI system. In a recent conference paper, Glenn Pritchard, Project Manager at Exelon in Philadelphia said "... In the past, the justification for AMR fell primarily upon labor savings in meter readings for energy billing purposes. Today, the benefits of enhancing customer services, and optimizing asset utilization and distribution operations outweigh savings from labor reduction."

How Can AMI Help Out?

AMI systems provide real-time links to each and every customer. Data thus obtained greatly assists the following OM processes:

- **Outage Detection** AMI should provide utilities with outage notification reliably, within a short time of the outage. Utilities should specify how quickly they wish to be informed of an outage to avoid reporting momentary outages that do not require any further immediate response. Interestingly, outage detection by AMI generally may not beat the first call from customers, but will clearly beat them when nobody is there, or when customers are asleep.
- **Outage Extent Mapping**, once triggered, determines the exact extent of each outage. It requires some knowledge of the distribution network connectivity model and utility escalation rules. It can be trigged by the AMR Outage Detection sub-system or the utility OMS, VRU, call center, and other related systems. It must be smart enough to identify nested outages and is extremely useful during major

storms. Extent mapping can be particularly helpful in analysis to separate single customer outages from bigger ones, as it eliminates the need to wait five to 30 minutes for the second customer call to come in. Better and faster analysis results in reduced outage times.

- **Outage Restoration Monitoring** works very closely with Outage Extent Mapping and runs in near-real time to monitor the progress of outage restoration. It provides positive verification that all customers have actually been restored before restoration crews leave the area. This monitoring eliminates the "stragglers" left behind when tickets on nested outages are closed prematurely. It can also feed outage data to reliability indicators, facilitating more accurate reporting. Restoration monitoring is extremely useful during major storms.
- **Momentary Outage Monitoring** manages the momentary interruption (blink) counter data from each meter. Individual meters can be aggregated by geographic areas to look for potential problems, such as a tree limb rubbing on a distribution line when the wind blows. Momentary outages can be eliminated before they become extended outages requiring emergency repair. It also eliminates the annoyance of blinking lights.
- **Real-time Information** is easily accumulated and made available to the utility OMS for on-the-spot analysis. This is extremely important since it provides Care Center reps and Integrated Voice Response systems with the answer to, "When will my power be back on?"

This AMI tie-in and assist to OM has long been talked about as a high-value, potential benefit, but for many reasons, it remained pretty much in the background. Until recently, full AMI integration with a utility's Outage Management System (OMS) was often treated as an interesting experiment, one not quite ready for prime time. Even though it would seem sufficient benefits have been there all along, obstacles in moving forward have been a lack of corporate commitment, a limited understanding of the benefits, and a belief that getting there was too difficult or costly. I attribute many of these obstacles to the silo mentality pervasive at many utilities in the "old days" and, unfortunately, still around, albeit, to a much lesser degree, today. AMI systems were often justified and purchased by meter readings folks, and what do they really know about outages and service reliability? Fortunately, the enlightened utilities have figured out that reliability is everyone's business.

What has changed? First, we have reached a critical mass in success stories. At industry conferences, Outage Management and AMI are frequently discussed together with sufficient examples of benefits that it is harder to support the belief that it can't reasonably be done. The successes are just too compelling to ignore. Second, I think the industry has done a much better job of integrating these systems in a way that makes sense and makes them more affordable. Meter Data Management Systems (MDMS) are providing the glue that tie utility AMI systems to OMS and other legacy systems. The use of industry standards such as ANSI C12.19 and C12.22, IEC 61968, and MultiSpeak® are helping reduce the cost and difficulty in integrating these multiple and disparate utility systems together. Placing a MDMS between multiple AMI systems and the OMS eliminates the need to develop multiple point-to-point, proprietary interfaces, saving money, time, and reducing risk. This also reduces the need to customize each legacy application to accommodate the requests and responses for data in differing styles and formats. A good MDMS does all this "translation" for them. Further, as additional utility systems tie into the wealth of information available, the more valuable the AMI data and AMI capabilities become to the utility enterprise.

Success Stories

Oliver Price, Director of District Customer Services at Rappahannock Electric Cooperative (REC), serving about 95,000 customers in Virginia reported in a recent conference presentation that for the 10 days following Hurricane Isabel "... REC handled 81,000 outages calls ... and ... AMR saved valuable personnel resources, helped to reduce the restoration time by two days, and avoided estimated bills to customers."

Michele Pierzga, Special Project Manager at PPL Electric Utilities (PPLEU), serving 1.35 million electric customers in Pennsylvania, reported at another recent conference that following Hurricane Isabel, PPLEU realized the following benefits in using its AMI system to help with the restoration "... reduced restoration costs, reduced revenue losses, estimated six hour reduction in total restoration time, 0 percent lost billing reads, 0 percent estimated bills due to Isabel, and 100 percent bills issued as scheduled." Pierzga also reported that their ongoing use of AMI to verify the status of a customer's power as they call in to report outages has reduced the number of outage calls dispatched by approximately six percent.

Glenn Pritchard at Exelon has a similar Hurricane Isabel story. In his conference paper, he reported "... the AMR system was used to analyze 2,300 events resulting in 950 of the events cancelled on the spot, another 100 events being escalated into transformer events and the remainder confirming the customer's outage. The estimated savings for this use was just under $0.5 million." Glenn further reported "...through the first nine months of 2004, the On Demand tool was used to cancel over 2,750 jobs and escalate 700 jobs into transformer outages all leading to prompter response times. This equates to nearly $350,000 of avoided cost and overall O&M savings." Mr. Pritchard had stated the "... project to link its AMR and OMS systems was approved with the expectations that the project would provide a means to reduce system CAIDI (Customer Average Interruption Duration Index) by up to four minutes, while providing nearly $400,000 savings in reduced O&M expenditures annually." Exelon got what it was hoping for, and more. The benefits continue to accrue. In another example, AMR allowed Exelon to cancel 1,200 single-customer outage calls and to escalate more than 750 single-customer outage calls into primary transformer events after a series of thunderstorms caused 400,000 Exelon customers to lose power on July 18, 2006.

The PPLEU and Exelon experience using AMI to reduce "false" outage calls is not unique. Utilities report that, upon field investigation, as many as 40 percent of their single lights-out calls turn into inside, customer problems. AMI provides Customer Care Center reps with real-time data and the assurance to step customers through checking out their internal problems without needing to dispatch crews to investigate. The 40 percent inside trouble number will not get reduced to zero, but experience tells us it will be reduced very significantly. A reduction of several thousand to tens of thousands of outage calls a year, at $50 to $100 per call translates into real dollar savings for those utilities "fortunate" enough to have this capability.

AMI data significantly improves operational efficiencies in the whole outage process. All aspects of outage get touched. Further, reliability indicators have been demonstrated to improve. Glenn Pritchard and David Glennwright, in a recent article on their experiences, reported that Exelon has achieved actual reductions in CAIDI of 1½ to 2 minutes due to the faster identification of outages and an additional 3½ minute reduction due to more accurate reporting of power restoration. They also reported experiencing a 15 minute reduction in analysis times for typical fuse and transformer outages. These results are real and substantial.

It is crucial to see the whole picture when dealing with outage processes and power quality (PQ) issues. Even when a utility thinks it knows a great deal about the situation, diving in more deeply often reveals gaps. As an example, consider "downtown network" distribution systems, known generally for providing high reliability. Customers in these systems are served from multiple distribution transformers through a maze of interconnected transformer secondary conductors. When all is well, reliability is great, but when there are problems, it is very difficult to know exactly which customers are affected by outages or other PQ issues. Supervisory control on the distribution feeders and telemetry on the network protector's help, but the maze of secondary conductors makes it difficult to associate customers with problems. This is the ideal application for an independent AMI / OMS link directly to each customer. AMI eliminates the confusion, thereby reducing the potential for mishandling customer problems. As a parting thought, customers normally receiving the highest levels of service reliability tend to be the most annoyed when they ask, "Why don't you know my lights are out?" Fortunately, with AMI, we have the answer. The answer is a good one, resulting in everyone winning: customers, utilities, regulators, and shareholders.

BIOGRAPHICAL INFORMATION

Randy Cough
Director Electric T&D Solutions
GE Energy

Specific Responsibilities

Mr. Cough is responsible to provide strategic direction and vision for the Electric Utility software segment for GE Energy's Network Reliability and Services group. Understanding customer needs matched with Advanced Distribution and Outage Management Systems along with technology solutions is the key element in GE Energy's vision of network management. Our customers are continually managing their capital expenditures and operations costs in relation to their network capacity and reliability. GE Energy's vision is to be the company that customers turn to in solving their capacity, reliability and cost equation issues. In addition, Mr. Cough provides executive leadership and consulting based on industry knowledge for the procurement and implementation of GE Energy's Electric Utility Software solutions to ensure customer satisfaction.

Past Experience

Mr. Cough has more than 30 years of utility, consulting, and project management experience with the last 15 years specializing on Electric Transmission & Distribution system solutions relating to outage management systems, distribution management systems, engineering management and design, geographic information systems, network asset management, mobile workforce management systems integrated with other Utility applications.

Educational Information

B.S. – Engineering Clarkson University

Professional Memberships

GITA
Institute of Electrical and Electronics Engineers (IEEE)
Project Management Institute (PMI)

Utility of the Future – Enhanced benefits by integrating OMS and AMI Technology

Randy Cough
GE Energy
8 Carrington Pt, Bluffton, SC 29910

ABSTRACT

Advanced Metering Infrastructure (AMI) technology has offered a tremendous savings to electric utility companies in the collection of meter information. However, AMI also has the ability to detect customer outages and provide other advantages to the process. Many Electric Utilities have integrated AMI technology into the distribution and outage management process to verify customer calls, enhance outage prediction, identify nested outages and verify restoration. This presentation will outline how the AMI system integrated with a Distribution and Outage Management System can provide additional benefits to Electric Utilities.

Overview

Utility Business Drivers and Challenges today

As Electric Utilities look to the future with the intense pressure to improve reliability, operational efficiencies, and customer satisfaction, Utilities will require advancements in Distribution Management and Operational Management Systems along with integration with other utility enterprise systems to meet the growing demand for operational improvement. Evolving business and regulatory challenges have resulted in utility demands to use DMS and OMS tools seamlessly integrated with other technologies such as AMI to manage Outage Management processes with regards to unplanned outages, while also managing complex and heavily loaded distribution networks with advanced distribution applications.

Utilities are seeing the increasing requirement for the amount of automation and data collection points being applied to customer premises and utility networks. Regulatory decisions may and will directly drive deployment of advanced metering independent of economic calculations. Regulators have very good reasons for directing utility actions, including fairness, value to the society as a whole, and quality of service. For example, regulated utilities in California and Ohio are now responding to regulatory direction to submit plans large-scale AMI deployments with costs and overall benefits the customers and utilities.

As Utilities reconcile the strategic AMI business case and the find ways to recoup the investment for AMI deployments, utilities are also able to see line of sight to many other benefits associated with AMI specifically around operational efficiencies.

To enable immediate benefits of Automated Meter Reading (AMR) the Automated Metering Infrastructure (AMI) will need to be architected and has now transformed into what most utilities are coining the "Intelligent Grid". When considering an intelligent grid, the investment can be significant, however by considering a phased investment approach several "non-metering" benefits can be achieved over time.

Many utilities may be still deliberating on the fundamental question "What is the Intelligent Grid"? The following key functional capabilities should considered for the enablement of an Intelligent Grid:

- An open and standard based architecture that will carve out the path for future technologies beyond the meter
- 2-way communications with smart devices distributed across the power systems with associated software applications analytics/decision support tools which enable the following:
    - Remote reading, connect/disconnect, TOU & real-time pricing, Load profiles/forecasting, Demand Side Management (DSM)
    - Detection & verification of outages
    - Volt/VAR Management
    - Transformer Asset Management
    - Improve circuit utilization
    - More efficient deployment of field personnel
    - Replacing static wallboards with a real-time digital network

<u>AMI Integration with Utility Distribution Operations</u>

As many Utilities have replaced legacy outage management systems with advanced geographic based systems, the utility can enable new business processes which will provide for a complete set of network management functions supporting not just outage management functions, but also enterprise outage management solution. This will allow utilities to achieve another level of operational benefits and capabilities across entire organization.
Many utilities are still faced with challenges from the deployment of OMS solutions based on the limited capabilities of today:

- Utilities and OMS solutions are still dependent on customers to report outages
- Device prediction accuracy – Utility data show that up to 30% of the single customer calls are not classified as outages
- Detection and verification of nested outages – nested outages can go un-noticed for several hours during Severe Storms
- Crews management & utilization – Crews dispatched to the in-correct location or return trips for Nested Outages are costly to the utility
- Ability for dispatchers to have greater visibility of system conditions

With the deployment of Intelligent Grid and AMI the utility has the ability for network operators to proactively manage large and complex networks in a more advance way. Today's AMI technology capabilities allow the network operators to:

- Ability to Ping any Device or Meter at any time
- Ability to Ping a meter & verify a no-light call
- Ability to evaluate the entire circuit or feeder
- Provide the network operator with prediction validation

- Provide additional information for locating the faulted device
- Outage restoration verification
- Identification of potential nested outages
- Improved Network Operator System Visualization

Once the Operations Management System (OMS) software is integrated with the AMI system the network operations personnel can automatically ping the customer and verify the status of the meter. If the customer's meter pings in-service the call & order can be cancelled which avoids a crew being dispatched to the site. This may be the simplest use of AMI but has the biggest overall impact and can eliminate approximately 30% of calls from being dispatched.

Another very important OMS business process improvement is with predicted outage validation and periodic outage assessment. With a 2-way integration of OMS and AMI system, customers under the predicted outage can be "pinged" a positive response from AMI for no-service verification. Outage orders or customers can be flagged for a follow-up action and if any customers ping in-service, the network operator can evaluate the entire circuit for nested outages to determine the correct interrupted device.

After restoration or partial restoration activities are completed, the network operators can verify restoration accuracy at the customer level. The crew will verify the interrupted device was repaired and returned to normal for the OMS system along with AMI to automatically ping the meters involved in the outage. This action will verify a restoration result regarding "no-power" on an individual customer basis. If for instance, the customer ping as still being out of service, the OMS prediction process will start over and a nested outage will be created for additional follow-up action while the crew is still in the area. This is a significant improvement to the overall restoration efforts and customer satisfaction.

Finally looking forward, the AMI infrastructure will allow for many other future Distribution Operation Management capabilities and improvements.
The enablement of AMI and additional data elements allows the utility to deploy additional real-time monitoring, control and management solutions.
Distribution Management applications such as:

- Distribution – Automated Feeder Restoration
- Distribution Power Analysis - Real time unbalanced load flow
- Volt/Var Optimization - Multi-objective optimization system

Challenges and Issues to keep in Mind

Although there are many benefits that can be realized with an integrated Distribution Management and AMI system, utilities will still have challenges to overcome. Some of which are:

- Communication Network – performance, scalability, redundancy
- Maintaining the Operated Network Model - As Switched Model
- Reliability of information - AMI notification / Ping notification
- OMS integration with AMI – Ability to "turn-off" AMI specifically during Storm

<u>Summary</u>

The integration of AMI and OMS can offer several benefits to the utility.

- Outage notifications are immediate – AMI can provide initial outage reporting & more accurate information
- Customer Call Volume can be significantly reduced
- Advanced outage prediction – Enables dispatchers the ability perform additional device analysis and improve accuracy of outage predictions.
- Dramatic reductions in field trips to single customer outages – meter status can be validated for non-utility problems
- Restoration processes are enhanced – ability to validate all or selected meters avoids nested outages
- Improved crew utilization
- Customer Satisfaction with proactive communication and status
- Improvements on identification of outages and momentary data

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Outage Management with AMR at PECO

Glenn A. Pritchard, PE

4/16/2007

TRANSMISSION & DISTRIBUTION METERING
T&D M
OPERATIONS AT WORK

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Topics

- ✓ PECO
- ✓ Scope of AMR at PECO
- ✓ AMR & Outage Management
- ✓ PECO's AMR/OMS Project

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Exelon / PECO

- ✓ Subsidiary of Exelon Corp (NYSE: EXC)
- ✓ Serving southeastern Pa. for over 100 years
- ✓ Electric and Gas Utility
  - 1.7M Electric Customers
  - 470K Gas Customers
- ✓ 2,400 sq. mi. service territory

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Scope of AMR at PECO

- ✓ PECO's AMR installation project lasted from 1999 to 2003
- ✓ A Cellnet Fixed Network solution was selected.
  - 99% of meters are read by the network
  - Others are drive-by and MV-90 dial-up
- ✓ During the project, meters were activated at a max rate of 143,500 per month.
- ✓ Installation was performed by PECO, Cellnet, and VSI.
- ✓ Cellnet manages the network, performs meter maintenance and provide data to PECO.
- ✓ All meters are read daily. Additional features include on-demand reads, and event processing.

PECO's AMR System

✓ Network Components

- 91 Cell Masters, ~8,400 Micro-Cell Controllers

✓ Services/Data Delivered:

- All meters are read Daily (Gas & Electric)
- Additional services include: Demand, ½ Hour Interval, TOU, SLS
- Reactive Power where required
- Tamper & Outage Flags (Last-Gasp, Power-Up Messages)
- On-Demand meter reading requests

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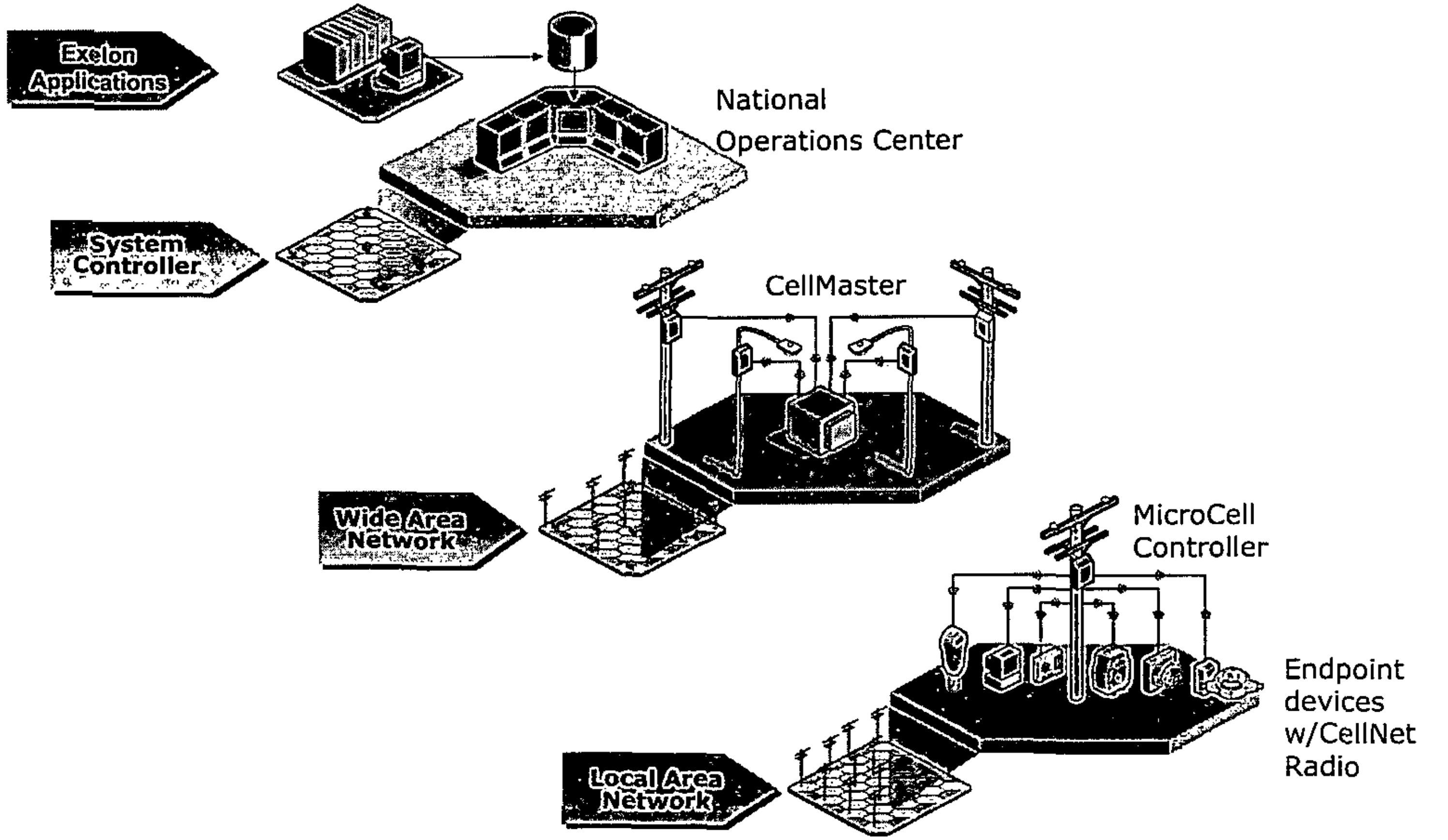
Cellnet AMR Network



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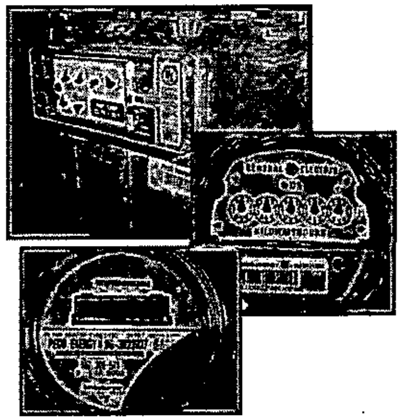
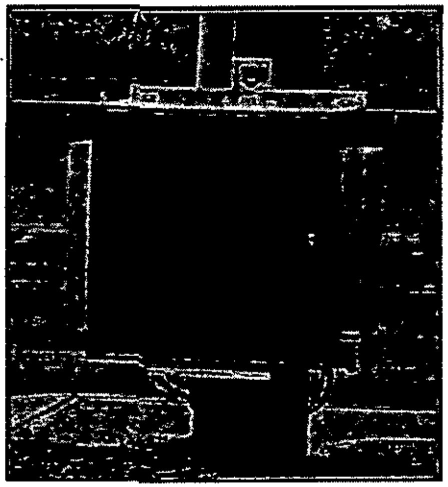
AMR Network Components

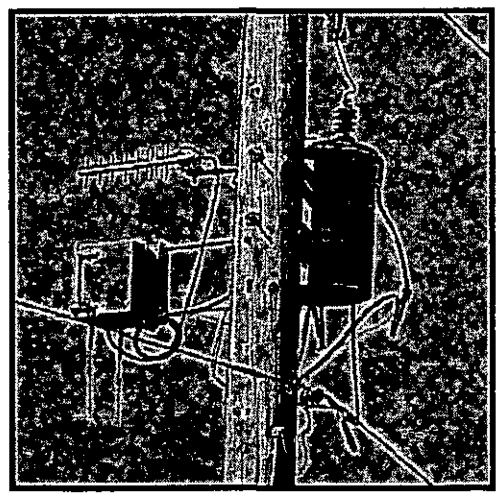


2,200,100 Meters
~1,625K Res. Electric
~455K Res. Gas
~135K Com. Electric
~42K Com. Gas



91 Cell Masters

8,400 MicroCell Controllers



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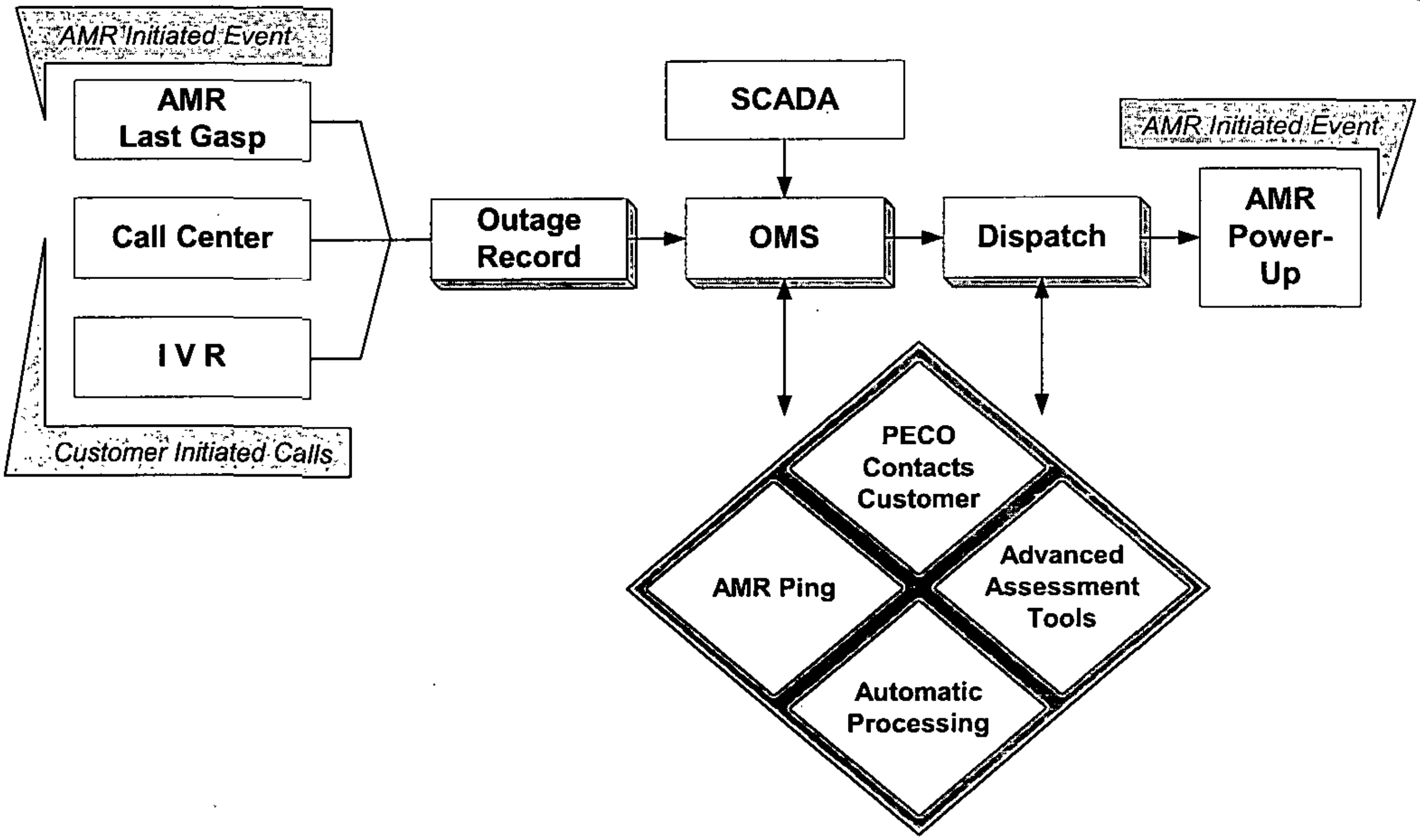
AMR & Outage Management

✓ Improved Customer Satisfaction
- Additional outage information
- More ERT's can be offered to customers
- Outage durations are reduced due to quicker response

✓ Power Status Verification
- Batch Pinging Meters
- Power-Up Messages

✓ Future Outage Prediction with LG's

Outage Management Process



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AMR/OMS Project Goals

"To provide the ability to remotely identify customer power status, to process outage messages and provide restoration verification data via the Cellnet AMR Network."

✓ 2 to 4 minutes in reduced System CAIDI through improved and reduced event analysis including better nested outage recognition.

✓ ~$400,000 annual O&M Savings from reduced overtime and outside contractor requirements through better event management.

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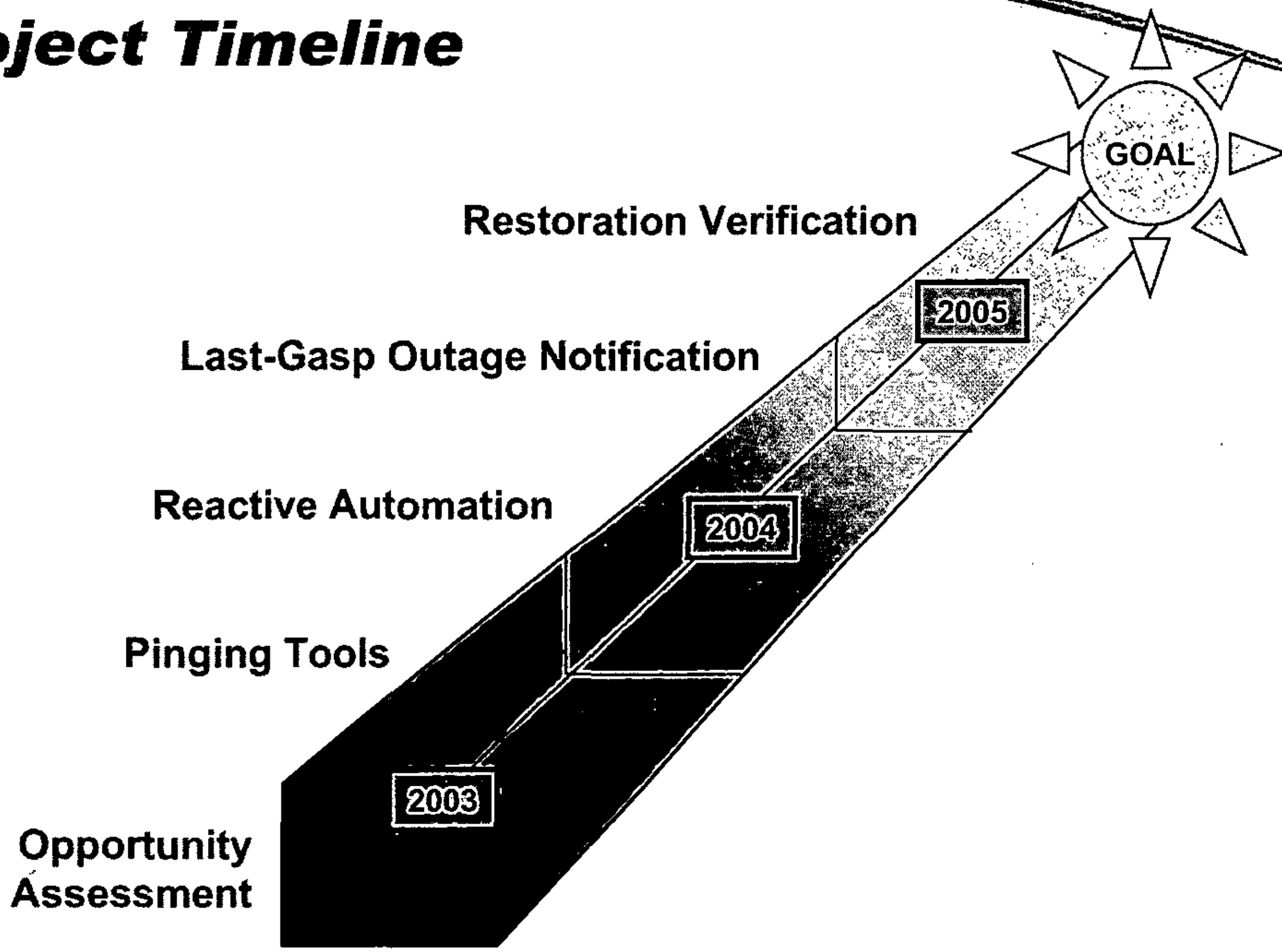
Project Timeline



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Outage Verification via "Pinging"

✓ What is Pinging?

- Querying the AMR Network to determine if a meter has recently communicated.
- A customer's power status is interpreted from the results of the query.
- If a meter has been heard from within the last 20 minutes, the power is inferred to be **ON**, otherwise the power is inferred to be **OFF**.
- Analysis Tools: Transformer Analysis, Circuit Analysis
- ~100,000 Pings annually

✓ When to Use:

- Checking to see if a customer is truly out.
- After hours.
- Verifying the validity of Job Packages prior to dispatch.
- Verifying that a job is complete.

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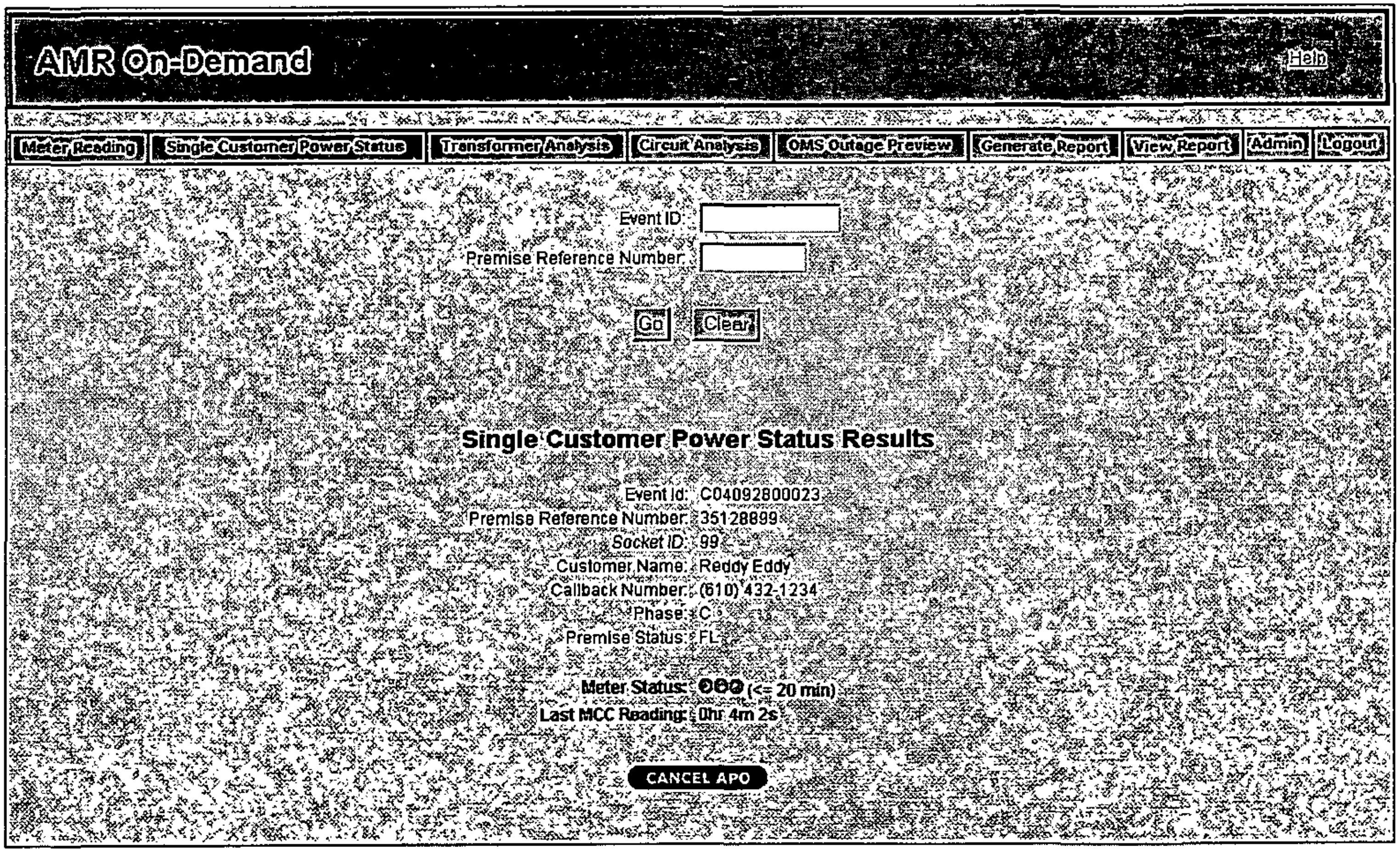
Pinging – Simple Ping Screen



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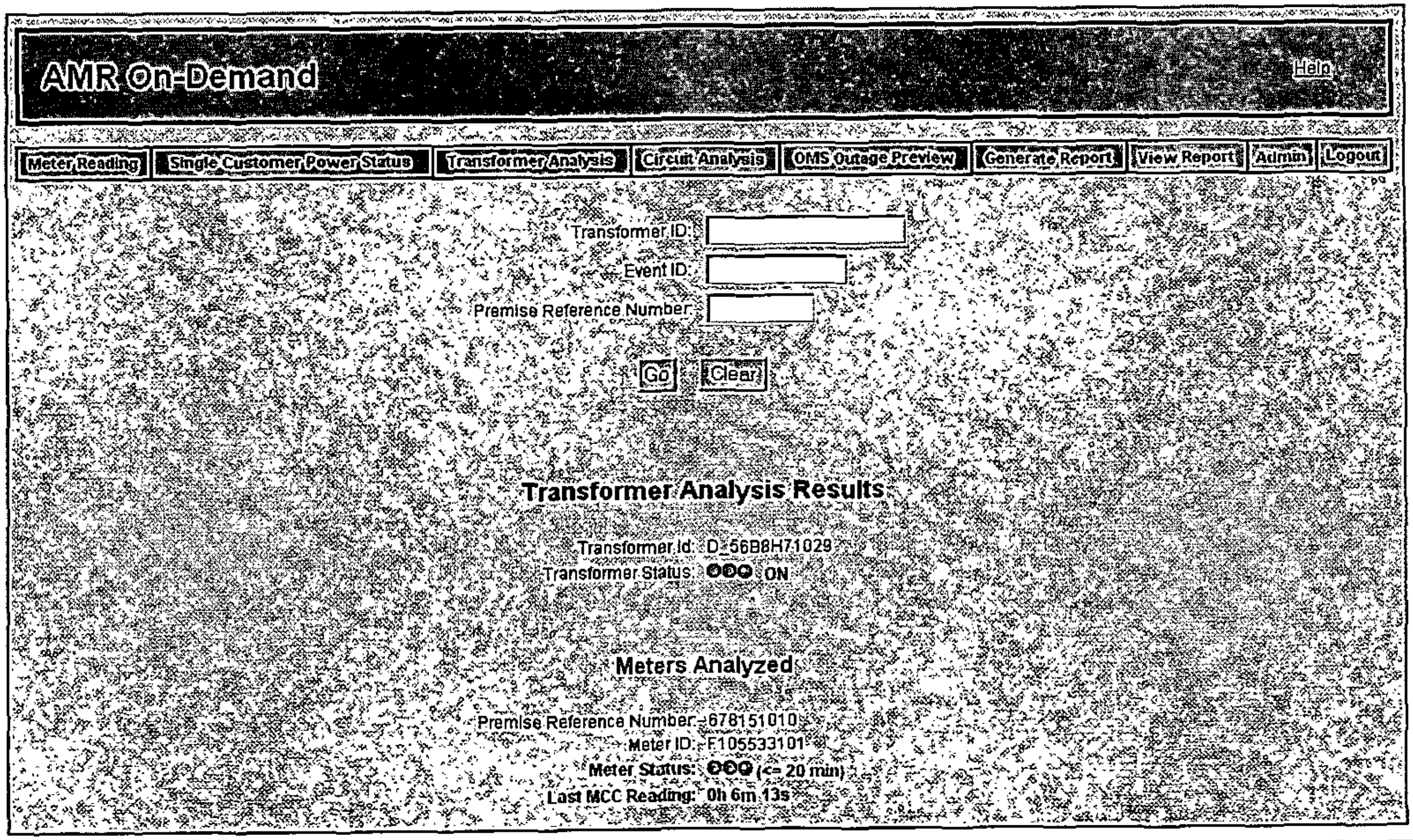
Pinging – Transformer Analysis Screen



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Pinging - Batch Results Screen

AMR On-Demand

Help

Meter Reading | Single Customer Power Status | Transformer Analysis | Circuit Analysis | OMS Outage Preview | Generate Report | View Report | Admin | Logout

Outage Call Report

Created on: 2/2/2007 8:23:02 PM EST by u002jtc

Export Report to an Excel Spreadsheet

Number of Requests: 24

Meter Reading MAGENTA: 0 (0%)
Meter Reading RED: 11 (46%)
Meter Reading GREEN: 13 (54%)
Meter Reading Waiting: 0 (0%)
Meter Reading Timed Out: 0 (0%)
Meter Reading SLB Error: 0 (0%)
Meter Reading General Error: 0 (0%)

Indicates SLB detected an outage the previous day.

Event Id	Premise	Meter	Outage	Type	Callback Number	Customer Name	
P07020200067	408310320	(> 20 min)	258h 40m 34s	PA	(215) 227-1968	CHERISE MEADOWS	TRF ANALYSIS
D07020200024	867279490	(> 20 min)	57h 37m 57s	PA	(484) 340-6099	ALISON Q HANNUM	TRF ANALYSIS
C07020200022	541858600	(> 20 min)	29h 35m 49s	AO	(610) 430-0743	susan	TRF ANALYSIS
P07020200030	936189260	(> 20 min)	10h 17m 7s	AO	(866) 322-4547	SHURGARD STORAGE	TRF ANALYSIS
B07020200027	677053400	(> 20 min)	5h 26m 25s	PA	(215) 297-8565	JOHN MAY	TRF ANALYSIS
M07020200035	916923900	(> 20 min)	4h 33m 3s	AO	(215) 514-1655	THOMAS VASOLI	TRF ANALYSIS
D07020200028	866083920	(> 20 min)	2h 39m 26s	AO	(610) 352-9720	TRUONG C CHAU	TRF ANALYSIS

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Automatic Outage Processing – "Reactive Automation"

✓ What is Reactive Automation?

- Automatic assessment of single customer outages.
- As a single customer outage ages beyond 20 minutes old, it is automatically pinged.
  - If the ping indicates Power-On, the outage is cancelled and the customer is notified via an automated callback.
  - If the ping indicates Power-Off, a transformer analysis is performed to potentially escalate the event into a larger outage.
- Only "plain vanilla" events will be cancelled, if there are comments, the outage will not be automatically cancelled.

✓ Results to Date

	2004	2005	2006	Total
Ping Results				
Cancels	5,450	6,184	11,584	23,218
Escalates	1,100	2,418	4,532	8,050

Last-Gasp Outage Notification

- ✓ What is Outage Notification?
  - Last-Gasp Outage Messages sent by the Meter.
  - Create outages similar to customer calls.
  - Time stamped when the message is received by PECO.
- ✓ Messages are heavily filtered
- ✓ When Last-Gasp Processing is activated

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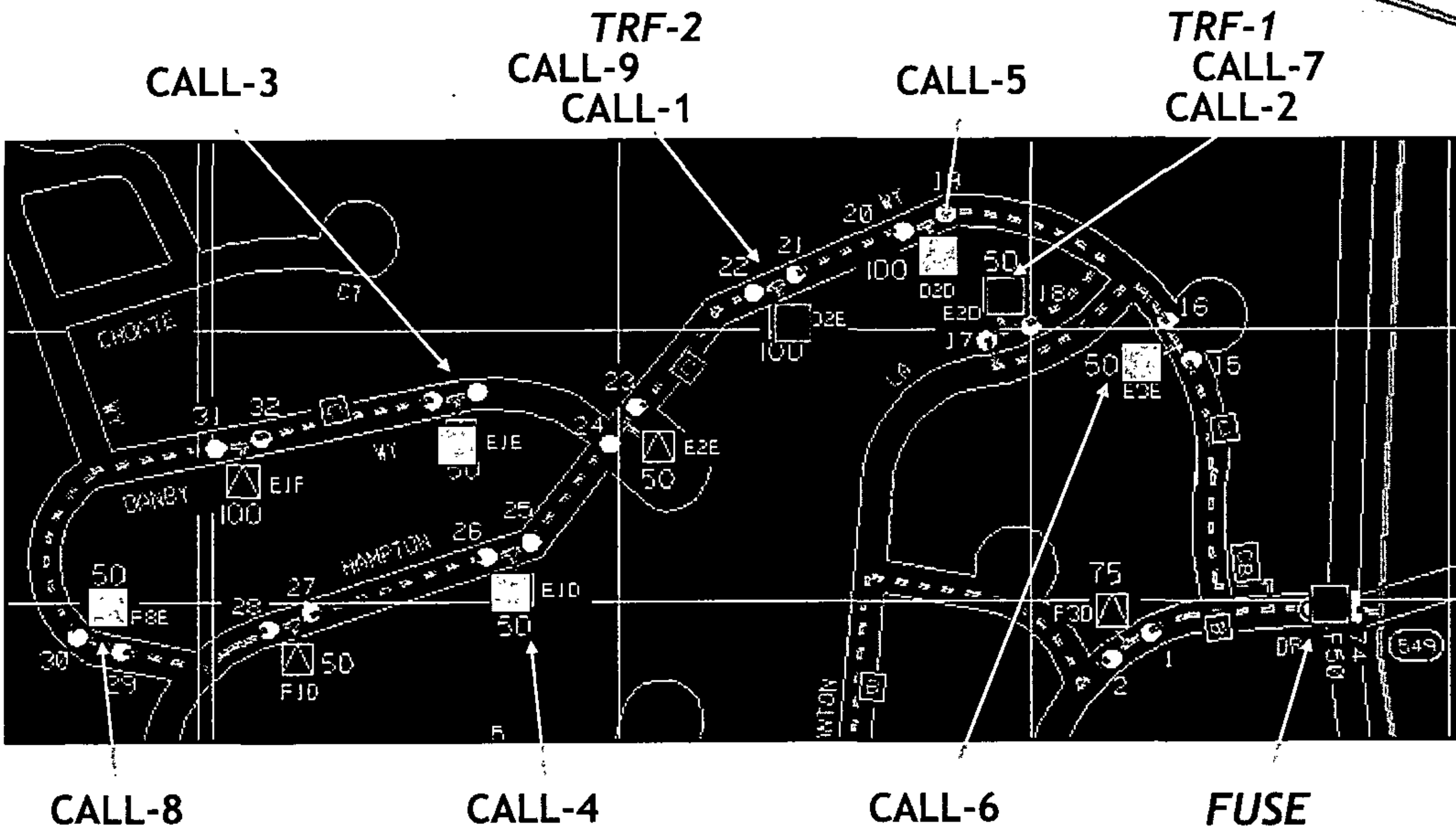
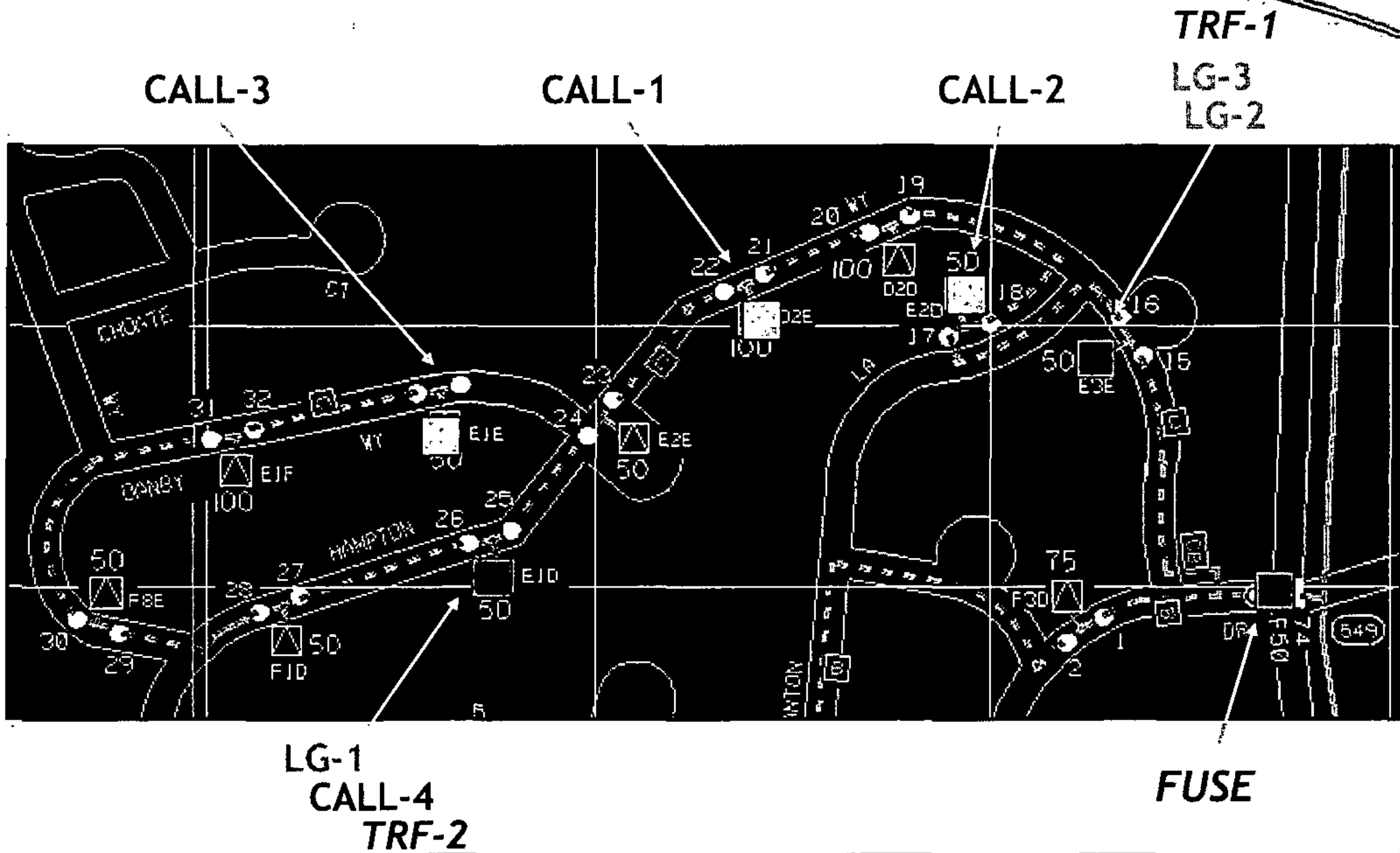
Outage Example



Event Time: 11:49:00

Customers Affected: 086

Outage Example w/AMR



Event Time: 11:34:00

Customers Affected: 086

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Notable Results

✓ "No customer call" events

- Outage is identified, Dispatched and Resolved before any customers notify PECO of the event.

- First identified event celebrated one month after activation.

- School Event.

- Ability to provide accurate ERT times to affected customers.

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Restoration Verification

✓ What is Restoration Verification?

- Power-Up Restoration Messages from the Meter.
- Reports have been created to leverage the Power-Up data:
  - Push Data History Reports
  - Power-Up Grouping Reports

✓ Uses:

- When closing events, to ensure all customers have been restored.
- During storm cleanup, "CAIDI Cop" role.
- Every Morning, to ensure proper CAIDI reporting.

✓ Sample results:

- 3.5+ Minute reduction in system CAIDI
- Improved field response and crew reporting

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Power-Up Grouping Report

Event ID	OMS Restoration Time	Number of Customers	AMR Group Timestamp	Deviation Minutes	# Power-Ups	% Power-Ups
P05120800032	12/8/2005 12:15	45	12/8/2005 12:10	-4	20	44%
			12/8/2005 12:15	0	3	6%
M05120800001	12/8/2005 3:30	550	12/8/2005 2:02	-87	362	64%
			12/8/2005 3:17	-12	3	0%
M05120700047	12/8/2005 4:09	466	12/7/2005 18:40	-568	220	47%
			12/8/2005 0:11	-237	6	1%
			12/8/2005 4:07	-1	2	0%
C05120800003	12/8/2005 9:20	7	12/8/2005 9:25	5	6	85%
M05120800020	12/8/2005 9:29	9	12/8/2005 9:46	17	8	88%
M05120800003	12/8/2005 10:38	9	12/8/2005 10:38	0	6	66%
P05120700174	12/8/2005 11:34	53	*No power ups*	0	0	0%
M05120800028	12/8/2005 12:25	10	12/8/2005 12:21	-3	7	70%
P05120800041	12/8/2005 13:17	233	12/8/2005 13:14	-2	150	64%
D05120800017	12/8/2005 13:25	2	*No power ups*	0	0	0%
M05120800025	12/8/2005 13:28	3	12/8/2005 13:17	-10	1	33%
B05120800017	12/8/2005 14:00	16	12/8/2005 13:57	-2	3	18%

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Push Data History Report

	Type	Event	Transformer	Premise	Socket ID	Cellnet Timestamp
1	LG	P05120800032	D_143B2G56368	27063431	99	12/8/2005 10:45
2	LG	P05120800032	D_143B2G56368	27063445	99	12/8/2005 10:45
3	LG	P05120800032	D_143B2G56368	27063448	99	12/8/2005 10:45
4	LG	P05120800032	D_143B2G56368	27063452	99	12/8/2005 10:45
5	PU	P05120800032	D_143B2G56368	27063431	99	12/8/2005 12:10
6	PU	P05120800032	D_143B2G56368	27063444	99	12/8/2005 12:10
7	PU	P05120800032	D_143B2G56368	27063452	99	12/8/2005 12:11
8	PU	P05120800032	D_143B2G56368	27063430	99	12/8/2005 12:11
9	PU	P05120800032	D_143B2G56368	27063438	99	12/8/2005 12:11
10	PU	P05120800032	D_143B2G56368	27063442	99	12/8/2005 12:11
11	PU	P05120800032	D_143B2G56368	27063441	99	12/8/2005 12:12
12	PU	P05120800032	D_143B2G56368	27063439	99	12/8/2005 12:12
13	PU	P05120800032	D_143B2G56368	27063433	99	12/8/2005 12:12
14	PU	P05120800032	D_143B2G56368	27063435	99	12/8/2005 12:12
15	PU	P05120800032	D_143B2G56368	27063437	99	12/8/2005 12:12
16	PU	P05120800032	D_143B2G56368	27063436	99	12/8/2005 12:13
17	PU	P05120800032	D_143B2G56368	27063443	99	12/8/2005 12:13
18	PU	P05120800032	D_143B2G56368	27063445	99	12/8/2005 12:13
19	PU	P05120800032	D_143B2G56368	27063449	99	12/8/2005 12:14
20	PU	P05120800032	D_143B2G56368	27063450	99	12/8/2005 12:14

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July 18th 2006 "Summer Slam" Event

A severe band of thunderstorms caused nearly 400,000 power outages.
Determined to be the worst summer storm ever experienced by PECO.

- ✓ 1,200+ single customer outage calls were cancelled without crew dispatch due to meter pings that indicated power-on.

- ✓ 750+ single customer outage calls were escalated into primary events via pings to neighboring customer's meters. This ensured a properly skilled crew was dispatched the first time.

- ✓ The pinging and restoration verification tools were used to confirm active jobs were valid prior to crew dispatch. Feedback from the field crews indicated that they felt like they were working more effectively because they had very few assignments that were "OK on arrival".

- ✓ Conservative estimates indicate that AMR has helped save in excess of $200,000 in avoided labor costs during this storm.

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Outage Prediction

✓ AMR Last-Gasp and Power-Up Messages

- 750,000 Last-Gasps Annually, 5% associated with actual outages
- 6,000,000+ Power-Ups Annually

✓ *Why? What do these messages mean?*

✓ Precursors

- Demonstrated to give advance notice
- Need to develop means to interpret these messages

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High Density of Power-Up Messages

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Outage Vs Power-Up Messages

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Conclusions

- ✓ The AMR/OMS project was a journey, from a concept to actual implementation.
- ✓ The project has created benefits well beyond the original estimates.
- ✓ The success of the project has advanced the AMR industry as a whole by proving that AMR-based outage management benefits are real.

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Thank You

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Exelon EED Meter Reading Technologies
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Philadelphia, PA 19101
☎ (215) 841-6977
glen.pritchard@exeloncorp.com

CA-IR-14

Ref: Application.

a. Please identify expected features in the proposed AMI system that might or will duplicate functions already provided by existing systems or processes in the Companies' operations.
b. For each identified duplicated feature or function, please provide a discussion of why some regulatory action should not be taken to remove the cost, at least in part, of one of the apparently redundant systems. For instance, if the AMI system will allow HECO to pinpoint outages and facilitate restoration, which were two of the features used to justify the need for the OMS, the Companies should identify the different capabilities of the OMS and the AMI and highlight why both systems are needed.
c. For each identified feature, please provide the estimated cost for that feature in each of the applicable systems. Please provide copies of the workpapers used to determine the Companies' response.

HECO Companies' Response:

a. Features in the proposed AMI system that might or will duplicate functions already provided by existing systems or processes in the Companies' operations could include the MVRS, and to a much lesser degree, Turtle[1], meter reading applications. With respect to the MVRS system, the AMI System will replace the majority of the meter reading transactions that are currently being performed by the MVRS system. The MVRS will still be required to perform the remaining manual meter reading as described in the Companies' response to CA-IR-1. The AMI model recognizes the reduction in the maintenance costs to the MVRS system.

With respect to Turtle, the Companies revised their AMI application to no longer omit the replacement of Turtle meters by AMI meters. As such, the expected reduction

[1] Turtle denotes the low speed, Powerline Carrier (PLC) system in use by MECO and HELCO for a limited number of customers.

in the maintenance cost for that system is reflected within the estimated Meter Reading Benefits.

b. No further regulatory action would be required with respect to MVRS. Once all Turtle meters are retired from service, the Turtle system will be deemed to be at the end of useful life and it will be retired by the Companies. In addition, as described in the Companies' response to CA-IR-13, the AMI system will not duplicate or replace any of the capabilities of the OMS System. As a result, no additional regulatory action would be required with respect to the OMS System either. It should also be noted that the Companies' AMI application is only targeting non-MV90 meters, and therefore the AMI system will not duplicate or replace any of the capabilities of the MV90 System.

c. The only workpapers used to determine the Companies' response to this information request pertain to the MVRS and the Turtle. The workpapers are provided in the Companies' response to CA-IR-2, Attachment 1. The cost (without AMI) of operating and maintaining the MVRS is displayed within the Meter Reading Outside Services in the response to CA-IR-2, Section IX.B.2. The reduced cost (with AMI) of operating and maintaining the MVRS is displayed within the Meter Reading Outside Services in the response to CA-IR-2, Section IX.C.6. A detailed narrative describing the calculations for the reduction is provided in the response to CA-IR-2, Attachment 2, Section IX.C.6.

CA-IR-15

Ref: AMI Project Cost Allocations.

a. Based on the understanding that only HECO has installed an OMS, please discuss whether HECO's customers might receive a greater level of benefits from the AMI, as compared to HELCO and MECO customers. Please provide copies of any analysis or study done to support the Companies' response.

b. Based on the Companies' disclosures (e.g., application, response to CA-IR-105 in Docket No. 2008-0083), the Companies propose to allocate costs for the MDMS and RNI based on customer counts. Please discuss, if each company might receive a different level of functionality from the same equipment due to various reasons (e.g., demographic differences, geographical differences, system differences), the reasonableness of relying on customer counts for allocation purposes. Please provide a copy of any analysis, etc. conducted to justify the reliance on customer counts for allocation purposes.

c. If not already addressed, Exhibit 9 includes a function of outbound email that would seem to be reserved for "key accounts." Please confirm that these key accounts basically represent commercial and/or industrial accounts.

   1. If yes, please explain why residential customers should be held responsible for a feature that would not directly benefit the residential customer class.

HECO Companies' Response:

a. The Companies' response to CA-IR-13 presented the synergies and benefits that could be achieved by interfacing the AMI and OMS Systems. Even though HELCO and MECO have not implemented OMS systems, their customers can still benefit from many of the outage management capabilities of the AMI System. With AMI, automated outage and restoration messages will be sent to the Meter Data Management System ("MDMS") which can be utilized to aid in detection of and restoration from outages. This information can also be utilized to greatly improve the tracking and reporting capability for HELCO and MECO. Exhibit 9, page 6 of Figure 4 to the Application illustrates the AMI System's capability to graphically present real outage events even without an OMS System. There has been no analysis to determine which of the HECO Companies would obtain the most benefit from this capability.

b. As stated above, there has been no analysis performed to determine which of the Companies would obtain the most benefit from this system. The majority of the costs that are applicable to this cost sharing allocation are specific to the MDMS since the Regional Network Interface ("RNI") is a hosted system. The vast majority of RNI operational costs are covered under the Network Service Fee which will be charged directly to each company based on its installed AMI meter population. This cost sharing mechanism was initially established under the CIS application. The cost will be allocated based on each utility's customer count, as the MDMS will manage all of the companies' customers' meter data.

c. Page 2 of Exhibit 9 (MDMS Architecture) to the AMI application includes a notation "high/low consumption for key accounts, etc" – the outbound e-mail from the MDMS can be configured, using business rules, for any account or group of accounts. There is no system or process limitation reserving this functionality for key residential or commercial & industrial customers.

CA-IR-16

Ref: AMI Pilots and Evaluation of the Systems.

On page 18, the Companies indicate that it has conducted three AMI pilot projects.

a. Please confirm that these three AMI pilot projects all evaluated Sensus AMI technology.
b. Please discuss whether the Companies evaluated any other AMI technology as extensively (i.e., conducting three pilots for each). If so, identify each AMI technology that was tested.
c. If the Companies did not conduct extensive testing of each of the other technologies, please discuss the possibility that the selected system may not be the most cost effective system that should be implemented. Please provide any documentation that supports the Companies' response.
d. Please confirm that all of the sites that the Companies have conducted their tests are on Oahu (i.e., Waikiki, Salt Lake, Makakilo, Koko Head, Pu'u Papa'a, Palolo, Tantalus, and Pauoa).
    1. Please discuss whether the Companies have done any additional analysis to ensure that the proposed system will be as effective in less urban areas, such as that found on the Big Island and in some areas on Maui.
    2. If additional analysis has not been done to verify the effectiveness of the proposed AMI technology on the other islands, please discuss what guarantees the Companies have obtained to mitigate the cost and performance impacts on affected customers.
e. On page 18, the Companies indicate that AMI is still being evaluated, developed and demonstrated. On page 21, the Companies indicate that it "anticipates installing and field testing the Sensus iConAPX (advanced, three phase commercial and industrial) meter." Please explain in greater detail whether the Companies have or have not conducted a full evaluation of the proposed AMI technology and have sufficient information to make an informed conclusion that the proposed technology will be the most cost effective solution for Oahu, Maui and the island of Hawaii. Please provide a copy of any reports or other analyses that supports the Companies response.
f. Please discuss whether the proposed AMI components are capable of interacting with alternative components that might provide greater functionality for geographical or demographic differences that might be found on Lanai and Molokai.
g. If the Companies have not fully completed testing and evaluating the proposed technologies and equipment types, please discuss whether the Companies' procurement and implementation plan for AMI allows for flexibility to accommodate possible changes.

<u>HECO Companies' Response:</u>

a. All three AMI pilot projects evaluated Sensus AMI technology and products under various conditions. HECO also piloted 24 Cooper Power Systems ("CPS") Faulted

Circuit Indicator ("FCI") devices equipped with Sensus FlexNet radios (for eight 3-phase circuits). The CPS FCI devices used for this test were the SCVT (Star Current Reset Variable Trip) model. The SCVT is a self powered (using current transformers) microprocessor controlled current reset unit that is designed to monitor current change (di/dt) events and detect faults. The Sensus FlexNet communications technology was integrated into the FCIs in order to enable them to communicate the FCIs' status to the TGBs.

b. No other AMI technology was evaluated as extensively by the Companies (i.e., to the extent of conducting three pilots each). In 2004, prior to evaluation of the Sensus FlexNet technology, the Companies performed limited testing of advanced metering prototypes from a small firm called MuNet (see Attachment 1 to this response). In 2005, the Companies worked on a Broadband Over Powerlines ("BPL") trial project and in 2006, expanded this BPL work to a pilot project (see Attachments 2 and 4c to this response). Confidential Attachments 4A and 4C summarize the results of the BPL pilot program and are submitted pursuant to Protective Order filed on April 15, 2009 in this proceeding. These documents contain confidential research and development information, and/or other nonpublic information that, if disclosed, may harm the Company's future competitive position. A high level BPL business case analysis was completed in December 2005 by KEMA (see Attachment 4a to this response) and concluded that BPL could have a breakeven period of 7-8 years but would require the Companies to complete a more detailed business case analysis since the results were sensitive to assumptions and operational scenarios. By the end of 2006, the Companies had terminated their BPL efforts and decided that more cost effective AMI solutions were now available (see Attachment 4b to this response). The Companies decided to decommission the BPL project in late 2006, after completing a small scale pilot project that focused on using BPL technology for utility applications such as automatic meter reading (see Attachment 3 to this response).

c. Exhibit 3 of the Application documents the Companies' AMI Technology Selection. After the Companies initial evaluation of Sensus FlexNet, the Companies made a decision to focus on further examination of Sensus' FlexNet (fixed network, licensed, narrowband, radio frequency) technology and did not pilot other AMI technologies. Given the rapid changes in the marketplace being driven by the keen interest of the Smart Grid at the national level; the Companies are keeping a close watch on AMI technology developments and deployments through discussions with utilities that are piloting or implementing AMI. In addition, the Companies participate in industry conferences.

d. Exhibit 6 of the Application shows the TGB locations and meter coverage on Oahu. There have been no AMI piloting efforts on Maui or the Big Island, although Sensus has provided network design studies covering those islands. Upon successful demonstration of the Sensus FRP on Oahu (see page 10 of Exhibit 11 of the Application), the Companies plan to pilot a small number of Sensus FlexNet meters in concentrated areas of Maui and the Big Island in 2009 and 2010. This will provide staff at MECO and HELCO with some early operational experience with AMI.

1. The piloting efforts on Oahu covered diverse areas and topographies including urban and rural. Concentrated deployments included the Ocean Pointe Development in the flat Ewa plains and the mountainous Tantalus/Palolo/Pauoa area. There will be some areas within each of the three companies' service

territories that will not be covered by this technology, as described in the Companies' response to CA-IR-1.

2. Section V.B of the AMI Application discusses the Companies' request for approval of the Sensus Agreement, executed between the Companies and Sensus Metering Systems ("Sensus") on October 1, 2008. That agreement requires Sensus to provide the AMI Network as a service subject to service level requirements, which provides some level of risk mitigation for operational costs. Other risk mitigation measures are provided in the Network Coverage (Exhibit D), the Performance Specifications (Exhibit E) and the Acceptance Tests (Exhibit H) sections of the Sensus Agreement. The meters are provided with a standard warranty period (up to 18 months from delivery). Sensus offered an extended warranty option (see Attachment 5 to this response). Confidential Attachment 5 describes the option contract of an extended warranty from Sensus and is submitted pursuant to the Protective Order filed on April 15, 2009 in this proceeding. This document contains commercial, financial, and vendor information, and/or other nonpublic information that, if disclosed, may harm the Company's future competitive position. Due to the high cost of the extended warranty, the Companies do not expect to select the extended warranty option.

e. HECO has evaluated the Sensus FlexNet technology within the limits of the Companies' available resources and available time. However, due to HECO resource limitations and the evolving nature of this technology (both hardware and software), thorough testing is difficult to achieve within a pilot environment. Final testing will be achieved within the system acceptance testing prior to full deployment of the technology.

In addition, in early 2009, HECO established a Smart Grid task force and initiated preliminary Smart Grid roadmapping activities shortly thereafter. With the availability of American Reinvestment and Recovery Act ("ARRA") funds, this effort has been accelerated. An RFP for competitive selection of a Smart Grid consultant will be issued in mid-2009 after the detailed work scope for this work is completed.

f. Yes. The AMI network has the capability to employ devices such as the Sensus FRP, which provides direct communications backhaul from Sensus AMI meters. This device may provide an economical solution to the smaller number of meters on Lanai and Molokai. Alternatively, Lanai and Molokai may benefit from TGB coverage that extends from Maui. Signal strengths on Lanai and Molokai can be assessed once TGBs on Maui are installed. Relative to the FRP, HECO will soon be testing this device on Oahu in 2009 (see Exhibit 11, pages 8 through 11, of the application).

g. Given the rapid changes in the marketplace being driven by the keen interest of the Smart Grid at the national level, the Companies are keeping a close watch on AMI technology developments and deployments through discussions with utilities that are piloting or implementing AMI. In addition, the Companies are in contact with other utilities and participate in industry conferences. HECO continues to monitor the changing demands of smart grid and other initiatives to ensure that the AMI technology selection is synergistic with the Companies' future Smart Grid, and is in the best interest of the Companies and their ratepayers. Other utilities such as Pacific Gas & Electric have made several key technology course changes, going from slow speed Powerline Carrier technology to higher speed RF technology, after installing hundreds of thousands of meters.

CA-IR-17

Ref: Sensus AMI Technologies.

The Companies indicate that a collaborative relationship with the Southern Company, Portland General Electric and Alliant Energy to share knowledge and experiences regarding Sensus AMI products.

a. Please provide copies of any recent reports, studies or analyses that have evaluated the efficacy and cost effectiveness of Sensus AMI products generated by or on behalf of the other energy services providers.
b. Please discuss whether the collaborative relationship with the other energy services providers include any cost reducing arrangements for the participants as it relates to AMI technologies.

HECO Companies' Response:

a. HECO has no copies of any recent reports, studies or analyses that have evaluated the efficacy and cost effectiveness of Sensus AMI products generated by or on behalf of the other energy services providers. However, the Companies participate in the Sensus FlexNet Users Group ("SFUG"), in which utilities are able to bring up issues, concerns, development requests, and solutions to problems encountered. The SFUG charter restricts the dissemination of information to SFUG members only. It is difficult to compare Sensus AMI product costs versus Sensus' competitors, as that information is typically confidential and only available during direct contract negotiations with the AMI vendors. The Sensus Agreement expressly restricts the dissemination of pricing information. Once the Companies selected Sensus as their AMI vendor, it became difficult if not impossible to obtain meaningful price quotations from other AMI vendors, as vendors placed their sales priorities and resources with more promising utility prospects.

b. The collaborative relationship with the other energy services providers has not revealed any directly quantifiable cost reducing arrangements related to AMI technologies. However, due to economies of scale related to these utilities' purchase of Sensus products, the Companies believe that the pricing contained within the Sensus Agreement is reasonable. As an example, Section 9.a(ii) of the Sensus Agreement contains the following provision:

> *Notwithstanding the foregoing, Sensus Meter pricing charged to HECO under this Agreement shall not exceed Sensus Meter pricing made available by Sensus to other utility customers for such Sensus Meters in like volumes and performance specifications.*

Other provisions manage the price escalation and fix the price of the Sensus meters during the deployment period.

CA-IR-18

Ref: AMI Technologies.

The Companies indicate that other technologies were also investigated and that those technologies include: cellular, Wi-Fi, and broadband over powerline. Application, page 18.

a. Please confirm that the Companies did not investigate and test other AMI technologies other than the three that were listed. If this understanding is incorrect, please identify the other technologies that were investigated.
b. For each of the other technologies that were tested, please provide the following:
    1. Dates that the pilot was initiated and terminated;
    2. Geographical area that was tested;
    3. Copies of any report or analysis that was conducted to evaluate the results of the pilot;
    4. Total project costs incurred for each pilot; and
    5. Reasons why the technology was not selected for this project.

    Please include copies of any documents that support the response.
c. If some of the other technologies were tested more than a few years (e.g., three) ago, please discuss whether the Companies considered that the technologies might have advanced such that those previously tested technologies might have advanced and been a possible alternative to the proposed technology. In other words, please confirm that the Companies did not rely on stale and/or dated data and technologies to reach its investment decision. Please provide copies of any analyses conducted to support the Companies' response.

<u>HECO Companies' Response:</u>

a. Prior to the Companies' focus on Sensus AMI technology, the Companies performed limited investigations and pilots of Wi-Fi technologies and Broadband Over Powerline ("BPL") technology. For special applications, the Companies have used and continue to use cellular modem-equipped, solid state meters (either under glass or external cellular transceivers), which have high capital costs and recurring cellular service fees. No pilots were performed with cellular technologies and no other technologies (besides cellular, WiFi and BPL) were investigated or tested by the Companies. See the Companies' response to CA-IR-16 for additional information.

b.

Cellular:

1. No pilots were initiated
2. Not applicable
3. Not applicable
4. Not applicable
5. Technology is currently too costly for widespread deployment but has use for specialized applications, including large commercial and industrial customers metering and AMI backhaul There appears to be an elevated level of interest in AMI and Smart Grid by cellular providers and many have announced partnerships with AMI vendors.

Wi-Fi Technology:

1. Discussions were initiated with Earthlink but no pilot was initiated. Limited testing was completed with MuNet meters in 2004 (see the Companies' response to CA-IR-16).
2. The Chinatown area was under consideration by Earthlink and the Company performed limited testing of MuNet meters in the McCully neighborhood.
3. Pacific Business News and some internet sites reported on the City and County of Honolulu, HECO, and Earthlink's short lived partnership (see Attachment 1 to this response and CA-IR-16 for the HECO report on MuNet meter testing).

4. Very limited costs were incurred for limited internal staff time and a small number of MuNet meters. Specific costs information for WiFi testing was not tracked.

5. Earthlink did not proceed with its Wi-Fi plans and the MuNet meter testing indicated that this product's performance was less than satisfactory (see the Companies' response to CA-IR-16 for the HECO report on MuNet meter testing).

Broadband Over Powerlines Technology:

1. Discussions were initiated with Current Technology in 2004 and trials/pilot work was performed in 2005 and 2006.

2. The technology was tested at the McCully Substation and in the surrounding neighborhood.

3. See the Companies response to CA-IR-16 for reports that were completed.

4. Approximately $700,000 out of an originally budgeted $2.7 million was expended on the BPL trials and pilot work (see the Companies' response to CA-IR-16 for additional details related to Docket No. 2006-0386. The BPL system was decommissioned and removed from the McCully testing areas in 2007.

5. Although BPL technology appeared to have a positive business case, field trials indicated that the technology was too expensive and not technically mature. As a result, the Companies decided to terminate BPL work.

c. Cellular technology has applications such as AMI backhaul communications but it is not cost competitive for use within low cost AMI meters. Wi-Fi technology is performance limited and AMI vendors are using RF mesh and fixed network solutions instead. Although BPL may have special applications on the utility grid, it's popularity with utilities has waned in recent years.

As noted in the Companies' response to CA-IR-16, given the rapid changes in the AMI marketplace being driven by the keen interest of the Smart Grid at the national level, the Companies are keeping a close watch on AMI technology developments and deployments through discussions with other utilities that are piloting or implementing AMI. In addition, the Companies are in contact with AMI vendors and participate in industry conferences. An important facet of this due diligence work by the Companies is to assess the interaction between AMI and the Smart Grid to ensure that the Sensus FlexNet technology is adequate for the long term. If another technology approach or even a revised approach with Sensus proves to be prudent, then the Companies are prepared to negotiate such an arrangement.

In light of the rapid escalation in Smart Grid activities and vendor developments related to the Smart Grid, HECO recently commissioned Enspiria Solutions (AMI/MDMS consultant) to conduct an AMI Industry Update, which will help the company assess the technology selection in light of AMI potential role in a Smart Grid. Enspiria authored a report entitled "Smart Grid Capabilities of Smart Meters" in May 2009 and the Companies are in the process of continuing this due diligence work in 2009. The purpose of the Enspiria study is to assist the company in assessing a technology selection that was made when full-featured AMI meters and systems were not available and Smart Grid was less visible. Other utilities such as Pacific Gas & Electric have made several key technology course changes, going from slow speed Powerline Carrier technology to several forms of higher bandwidth RF technology, after installing hundreds of thousands of meters. In recent months, through discussions with Enspiria and other information sources, the Companies have learned that more than one utility is facing similar situations. The Companies' intend to avoid that scenario.

FOR IMMEDIATE RELEASE
June 22, 2006
Release M-69-06

MAYOR ANNOUNCES FREE WI-FI IN CHINATOWN

Mayor Mufi Hannemann announced today at the Chinatown Summit that the City will establish a public-private partnership with Internet service-provider EarthLink (Nasdaq: ELNK) in a test to provide free, wireless, broadband access throughout Chinatown.

"As part of our commitment to the revitalization of Chinatown, we are happy to partner with EarthLink to bring new capabilities and to stimulate economic development in this community," said Mayor Hannemann.

"The City will also be testing new public safety technologies that the Wi-Fi environment makes possible," the mayor added. "We hope the result will be a safer and more economically vibrant Chinatown."

EarthLink has emerged as one of the leaders in municipal Wi-Fi development, having been awarded contracts in Philadelphia; Anaheim, California; Milpitas, California; and New Orleans.

"Chinatown has long been one of Honolulu's most historic neighborhoods, and adding EarthLink's municipal Wi-Fi will add to its allure," said Donald Berryman, executive vice president of EarthLink and president of the ISP's municipal networks unit. "Our no-cost solution gives residents and visitors an easy way to access the Internet, while at work or at play in one of the most interesting cultural areas on the island."

"We also are excited to work with Hawaiian Electric Company to help them test next-generation utility applications and services leveraging our Wi-Fi network," Berryman added.

As a unique feature of this Honolulu project, EarthLink will partner with Hawaiian Electric Company (HECO) to provide connectivity to test a variety of utility applications.

"Broadband Wi-Fi has potential to enable applications that can result in better service for our customers and future, new customer offerings," said Karl Stahlkopf, senior vice president for energy solutions and chief technology officer for HECO. "We look forward to being an active partner with EarthLink and the City in this progressive program."

The Wi-Fi program will test various utility applications, including advanced electric metering and energy conservation initiatives.

"This pilot project provides the City not only the ability to test and evaluate the technology for present and future needs, but also to work through the various legal and administrative processes," said Gordon Bruce, the City's chief information officer.

The Chinatown Wi-Fi demonstration project will begin later this summer and continue for approximately one year.

-30-

Contact:
Keith Rollman, Department of Information Technology, 768-7658
Gregg Hirata, Mayor's Office, 523-4051

Thursday, June 22, 2006

CA-IR-19

Ref: Application.

a. Please provide a copy of any analyses or studies conducted by the Companies to determine that the proposed AMI project is the best alternative by which to accomplish each of the goals and objectives identified in the application.
b. If not already identified elsewhere, please identify each of the alternatives considered before determining that an AMI project was the best alternative
c. For each of the goals and objectives identified in the application as justification for the AMI project, please provide a discussion of why the AMI project represents the most cost effective and/or reasonable means by which to attain those goals and objectives.

HECO Companies' Response:

a. The Companies are not aware of any alternatives that can provide the quantifiable and intangible benefits possible with AMI technology. Attachments 1 and 2 to this response provide more than sufficient motivation for the Companies to conclude that AMI will be able to cost effectively provide the benefits discussed in the Application. As shown in the Companies' AMI financial model (provided as Attachment 1 to the Companies' response to CA-IR-2) and the AMI Financial Model Narrative (provided as Attachment 2 to the Companies response to CA-IR-2), The AMI project provides a platform that will enable or further the accomplishment of other objectives. The costs of installing the AMI platform will be offset in substantial part (but not completely in a net present value basis) by certain direct, quantifiable benefits.

b. The Companies believe that intangible benefits will accrue to the customer and utility as a result of AMI implementation and future tangible benefits will also occur as other utility programs are implemented. The cost effectiveness of those programs will be determined by the Companies as they are developed.

c. As defined in Section VII.A, page 17 of the Application, the primary goals of the AMI Project are customer empowerment, improved customer service and cost savings, by providing or enabling capabilities such as:

- Advanced meter reads (monthly, on-demand, interval data, etc.);
- Remote disconnects/reconnects;
- Voltage level monitoring at the customer premise level;
- Power failure and restoration reporting (outage management support);
- Tamper detection;
- Energy theft recovery;
- Improved grid operations;
- CIS Integration; and
- Future DR programs.

Due in large part to the dramatic reduction in the price of AMI products and advanced feature sets, only AMI technology is known to have the capability to achieve all these goals.

d. Currently, only AMI technology is known to have the capability to achieve all these goals. The extensive feature set of today's AMI meters and integrated software systems provide an end-to-end solution that no other known technology can support. Each capability and the relevance of AMI technology to that capability is discussed below:

<u>Advanced meter reads (monthly, on-demand, interval data, etc.)</u>

AMI replaces current manual meter reading processes as well as older technologies such as drive-by and Powerline Carrier technologies. These systems are generally one-way systems that retrieve monthly consumption reads only. AMI provides interval consumption data at much higher rates, the ability to operate in a 2-way mode, and the ability to retrieve system data such as premise voltage and status information (power outage and restoration information). The 2-way mode is a critical feature that allows the Companies to send command and pricing signals to the customers and provide "on-demand" functionalities. Lastly, the 2-way mode allows the AMI meters to be remotely upgraded as new firmware capabilities are developed or meter configuration changes are desired, in effect becoming "software-based meters". No technology can provide this capability at the cost of new AMI technologies.

Remote disconnects/reconnects

Currently, the Companies have a limited number of solid state meters from Landis & Gyr that use Carina collars. This technology is about five times more expensive than the proposed AMI metering.

Voltage level monitoring at the customer premise level

The AMI meters send average, minimum, and maximum voltage information in each "read message". In addition, the Companies are working on methods to capture voltage load profile data for all or some of the AMI metering. This will provide unprecedented visibility into the Companies' electric network and be invaluable in forming a comprehensive, dynamic picture of the Companies' electric network. As a built-in feature of the AMI meter, there is no technology that can come close to this capability.

Power failure and restoration reporting (outage management support)

As in voltage monitoring, AMI meters provide power failure and restoration reporting as an inherent feature of their design and there is no technology that can rival this capability.

Tamper Detection and Energy Theft

Another inherent feature of the AMI meter is the ability to detect meter inversion (causing electromechanical meters to run backwards) automatically. Other solid state meters may have this particular feature but they have no way of reporting or recording these incidents. The AMI meter does both. In addition, the capture of interval data from the meter provides a large quantity that can be analyzed with business intelligence tools (revenue protection modules) to circumvent sites where electricity theft might be occurring.

Improved grid operations

The availability of interval consumption and electrical data (voltages, outages, restorations) and the ability to aggregate meters into virtual meter points provides unique opportunities to improve distribution planning and grid operations. The inherent features of the AMI system to provide this data cannot be achieved with any system that the Companies are aware of.

CIS Integration

AMI systems are developed to incorporate Meter Data Management Systems ("MDMS"), which are in turn designed to integrate with CIS systems. Tight integration of the Companies data from capture at the customer site all the way to billing is an efficient, end-to-end process. The Companies are unaware of any other system that can capture interval data, validate, edit, and estimate this data, and provide billing determinants to a CIS in a seamless manner while also allowing the Customer Service Representative (user of the CIS) to ping meters and request historical data from a meter data repository (i.e. the MDMS).

Future DR Programs

The 2-way communicating capability of the AMI system provides the platform to route DR commands to customer premises. Other technologies such as paging systems are used now by the Companies (and other utilities); however, the communication network will be available at no additional cost to support future DR programs.

Attachments 1 and 2 are voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the documents. Electronic copies of the requested information are being provided.

CA-IR-20

Ref: Application, page 18.

In footnote 18 on page 18, the Companies indicate that they are working with Sensus and other suppliers to develop and test various types of equipment that might be associated with AMI systems.

a. Please discuss whether the Companies are or will receive any type of revenues or discount on the equipment as a result of this work. If not, please explain why not.
b. If the Companies are receiving any type of compensation, whether in the form of payments or reduced costs, please confirm that these benefits will be recognized when determining the costs to be recovered from ratepayers. Please provide a discussion of how the benefits will be recognized.

HECO Companies' Response:

a. In reference to the footnote 18 on page 18:

The Companies are working with Sensus and other suppliers to develop and test such devices as "In-Premise Displays" and Smart Thermostats that provide such information. In addition, the Companies plan to develop a web portal to provide information to customers.

The Companies are not currently receiving nor do they expect to receive any type of revenues as a result of this work. The Companies' role, along with Sensus' other utility customers, is to provide input on desired features and to gain experience with new products and concepts. In the course of the Companies' ongoing AMI pilot work, the Companies have occasionally received limited quantities of test hardware and software at no cost or at a discounted cost. Working with suppliers and other utilities is prudent in guiding suppliers to commercialize products that are useful to the utilities and their customers. Depending on the extent and value of the collaboration with vendors, the Companies could realize and would negotiate arrangements with vendors to obtain discounts or revenues.

b. As proposed in the Application, during the deployment of the AMI system, all equipment expenses would flow through the REIP/AMI surcharge. As such, if the Companies can achieve cost reductions, they would be reflected through a surcharge adjustment. A detailed clarification of the proposed surcharge mechanism is provided in the Companies response to CA-IR-36.

CA-IR-21

Ref: AMI Technologies and Obsolescence.

a. Please discuss the guarantees, if any, that the Companies have received as it relates to technological obsolescence for any of the components of the proposed AMI project. Please provide copies of any supporting documentation.
b. Please discuss the guarantees, if any, as it relates to the support that will be available for various components of the AMI project, even if or when new upgrades are made available. Please provide copies of any supporting documentation.

HECO Companies' Response:

a. AMI technologies are developing at a very fast pace and the high level of interest in Smart Grid has put pressure on AMI vendors to expand their product and services offerings to include Distribution Automation and consider new communications architecture concepts. As such, the risks that were previously limited to AMI technology now encompass Smart Grid technology. AMI is generally thought of as an important building block for the Smart Grid.

For the proposed AMI project, HECO negotiated an agreement with Sensus that includes the following:

1) Network services provided by Sensus (instead of a HECO owned and operated model typical of traditional utility projects) with penalties for non-performance (i.e., service level agreement); and
2) Software configurable metering with metrology and radio firmware upgrades done over the air, without interruption of operations.

In the software area, the selection of the MDMS will be based on a comprehensive RFP template provided by an experienced AMI/MDMS consultant and the MDMS will be largely implemented by an experienced Systems Integrator. The

MDMS architecture will be selected in order to allow a free exchange of information between applications (i.e., using an enterprise service bus). The Sensus Agreement describes any available AMI system guarantees and the Companies do not have any documentation regarding MDMS guarantees since the requirements document and MDMS contract have not been awarded.

b. The Company analyzed and mitigated the risk of loss of support in the same manner as it addressed the risk of technology obsolescence. As an example, the Companies executed a 15-year contract with Sensus, which obligates Sensus to have full responsibility for network operations and equipment upgrades as necessary to ensure minimum performance standards and disaster recovery. Relevant details are provided in the Application: (1) Exhibit F - Statement of Work, and (2) Exhibit E - AMI System Performance Specification. Exhibit E specifies financial offsets if Sensus is not able to meet the required performance level. Section 10 of the Sensus Agreement provides HECO the right to purchase its entire AMI Network from Sensus.

Similarly, MDMS requirements will include development, implementation and long term operational and maintenance support, including a clear definition of upgrade rights. In the case of both hardware and software, it will be important to train an appropriate number of the Companies' personnel to monitor the AMI Systems and to be able to take over this role in a worst case scenario.

CA-IR-22

Ref: AMI Meter Installation.

a. On page 5 of the application, the Companies indicate that they expect to install a total of 451,000 meters (Oahu - 293,000; Maui – 66,000; Hawaii – 92,000). Please identify all of the customer classes that were considered in the projected number of meters to be installed.

b. Please provide the total number of meters for each customer class for each of the islands served by the Companies as of April 2009. Please reconcile any differences in the meters provided in response to this information request with the information disclosed in the most recently filed monthly financial report with the PUC.

HECO Companies' Response:

a. All customer classes are included in the projected number of meters to be installed. The AMI Application originally planned to replace approximately 95 – 96% of the commercial, industrial and residential electric meters. However as noted in the response to CA-IR-1 Section d, the Companies plan to update their Application to allow AMI meters to be installed to all customers. The only meters that are not included are MV90 and meters.

b. Attachment 1 to this response presents the total number of meters for each customer class for each of the islands served by the Companies for December 2007, December 2008 and April 2009, as disclosed to the Commission. It also provides the original 2008 and 2009 meter estimates from the AMI model. The Companies' response to CA-IR-2, Attachment 2, Section II.A.3 (Meter Population) describes the process used to develop the original estimation for the meter population by meter type. The original meter population estimate was performed on October 2007. Therefore, differences would be expected when comparing the meter counts to December 2007. In an effort to maintain consistency, the AMI model has been revised so that the 2008 meter counts within the

AMI model (see response to CA-IR-2, Attachment 1, Section II.A.3) now match the meter counts displayed in Attachment 1, Section A of this response.

Due to this revision of the 2008 meter counts and the change in the base assumption to replace 100% of the Non-MV90 meters with AMI meters, instead of the original plan to replace 95% of the Non-MV90 meters with AMI meters, the meter counts on the table on page 5 of the Application should be revised to reflect the following:

Island	**Number of AMI Meters**
Oahu	313,000
Maui	70,000
Hawaii	95,000
Total	478,000

Section A - Meter Counts from PUC Submittals	HECO			HELCO			Maui		
	Dec 07	Dec 08	Apr 09	Dec 07	Dec 08	Apr 09	Dec 07	Dec 08	Apr 09
VAR Meters	1,599 (1)	1,519	1,585	283 (1)	287	272	193 (1)	194	202
Total Meter Count	300,292	303,017	303,868	80,902	82,640	82,880	62,707	63,788	65,269
Total Meter Count Without Vars	298,693 (1)	301,498	302,283	80,619 (1)	82,353	82,608	62,514 (1)	63,594	65,067

Section B - Customer Counts from PUC Submittals by Class	HECO			HELCO			Maui		
	Dec 07	Dec 08	Apr 09	Dec 07	Dec 08	Apr 09	Dec 07	Dec 08	Apr 09
Residential	258,725	258,730	258,504	64,792	65,862	65,978	51,803	52,620	53,394
General Service, Non-Demand	*25,818*	*25,939*	*25,397*	*11,495*	*11,161*	*10,784*	7,613	7,479	7,414
General Service, Demand	6,709	6,641	6,717	1,618	1,652	1,630	1,383	1,375	1,385
Heating, Cooking, etc.	699	643	606	237	223	220	214	208	206
Large Power	353	341	380	70	70	70	122	122	134
Street Lights	125	124	125	26	27	27	15	14	14
Residential (Employees)	2,101	2,117	2,149	493	498	508	410	423	442
	294,530	294,535	293,878	78,731	79,493	79,217	61,560	62,241	62,989

Section C - Original AMI Submittal Meter Counts	HECO		HELCO		Maui	
	Dec 07	Dec 08	Dec 07	Dec 08	Dec 07	Dec 08
VAR Meters	1,529	1,519	279	287	193	197
Total Meter Count (no vars)	297,325	299,678	80,572	82,997	61,473	62,702

(1) *To maintain consistency, the AMI model has been revised so that the 2008 meter counts within* the AMI model (See CA-IR-2, Attachment 1, Section II.A.3) reflects these actuals.

CA-IR-23

Ref: AMI Meter Installation.

a. Based on certain responses to information requests in Docket No. 2008-0083 (e.g., CA-IR-216), HECO has already initiated the process of installing AMI meters. Please confirm that the information provided in response to CA IR 216 is the most current and accurate count of AMI meters installed on Oahu through the end of 2008.
b. In its response to CA-IR-216 in Docket No. 2008-0083, the Company indicates that a total of 776 AMI meters were installed in 2008 (as of October 6, 2008). The instant application indicates that 1,100 AMI meters were installed in October and November 2008 (application, page 19). Furthermore, the application indicates that approximately 7,700 AMI meters have been installed as of November 10, 2008. The difference between the 1,100 AMI meters identified in Docket No. 2008-0303 and 776 meters in Docket No. 2008-0083 do not make up the difference between the estimated 7,700 meters in Docket No. 2008 0303 and 7165 meters in Docket No. 2008-0083. Please explain.
c. Please provide the most current and accurate count of AMI meters installed on each of the islands served by the Companies through the end of 2008. Please provide this information by year.
d. Please provide the most current estimate of the projected number of AMI meters to be installed on each island in 2009 through 2015 by year.
e. Please provide the most current estimate of the projected number of non-AMI meters to be installed on each island in 2009 through 2015 by year.
    1. Please discuss the reasons why the Companies continue to project the need to install non-AMI meters if the intended goal is to replace all existing non-AMI meters with AMI meters.
    2. Please provide a copy of any analysis or study that suggests that the cost effectiveness of installing non AMI meters in 2009 and beyond, if applicable, is a reasonable cost.
f. Please provide the actual number of meters installed in 2009 by island and classify the installed meters by AMI or non AMI.
g. Of the AMI meters installed to date on each of the islands, please discuss how the decisions were made by the Companies to install AMI meters (e.g., customer request, pilot test, etc.) and classify the number of meters installed as a result of each reason.

<u>HECO Companies' Response:</u>

a. The information provided in response to CA-IR-216 is not the most current and accurate count of AMI meters installed on Oahu through the end of 2008. Attachment 1 to this response shows the number of AMI meters, currently installed, by their year of installation.

b. Section VI.B, of the application (Piloting Activities) describes the significant phases of the AMI piloting. It does not itemize each meter transaction (installation and removal) required to maintain and continue the Companies' evaluation of the AMI system. Attachment 1 shows that 1,846 AMI meters were installed in 2008. Some AMI meters have been replaced as a result of meter failures, new metering requirements or to facilitate testing new hardware and meter firmware versions. As an example, CA-IR-216 filed in Docket No. 2008-0083 showed that 394 AMI meters were installed in 2006 while Attachment 1 shows that only 316 of those meters are still installed.

c. The most current and accurate count of AMI meters installed on each of the islands served by the Companies by year is provided in Attachment 1.

d. Attachment 2 provides the most current estimate of the projected number of AMI meters to be annually installed on each island for the years 2009 through 2015.

e. Attachment 3 provides the most current estimate of the projected number of non-AMI meters to be installed on each island in 2009 through 2015 by year.

1. The current Application was focused on the need to install non-AMI meters until the year of their full AMI deployment due to the cost difference between the AMI and non-AMI meters in cases where the customer do not require time-of-use meters. In such cases, the cost of an AMI meter is just over twice the cost of a non-AMI meter. Installation of more expensive AMI meters prior to the availability of the MDMS System and the AMI Network would result in higher costs during a period when the benefits could not be fully realized by the customer. This approach could require the replacement of the non-AMI meter with an AMI meter in the future.

2. No analysis or study has been completed to determine that the cost effectiveness of installing non-AMI meters in 2009 and beyond, if applicable, is a reasonable cost. However, the Companies could adjust the current plan to avoid replacement of relatively new, non-AMI meters in the future.

f. Attachment 4 provides the actual number of installed meters installed in 2009 by island and classifies the meters as AMI or non-AMI meters.

g. AMI meters have only been installed on Oahu thus far. The vast majority of the meters have been installed for pilot testing. A few (less than 100) were requested by the HECO meter reading department to aid meter readers in locations where physical access is limited and/or potentially dangerous to meter readers. Very few of the installations were due to customer requests and the companies have not tracked the specific number of installations which were due to customer requests.

	Installed AMI Meters [1]		
	HECO	MECO	HELCO
2006	316	0	0
2007	5921	0	0
2008	1846	0	0
2009 [2]	520	0	0
Total	8603	0	0

[1] Includes all AMI meters currently installed on 4/30/09
[2] Only shows meters installed 1/1/09 through 4/30/09

	AMI Installation Plan		
	HECO	MECO	HELCO
2009	885	(1) 100	(1) 100
2010	2,246	0	0
2011	(2) 102,837	0	0
2012	(2) 103,627	0	0
2013	(2) 106,842	0	0
2014	(2) 2,444	(2) 69,731	0
2015	(2) 2,463	(2) 1,127	(2) 95,215

(1) MECO and HELCO are plans to perform a limited scale pilot test as described in CA-IR-16.

(2) CA-IR Attachment 1, Section II.A.5

	Non-AMI Installation Plan		
	HECO	MECO [1]	HELCO
2009	4,221	2,340	3,150
2010	5,220	2,370	3,154
2011	0	2,408	3,344
2012	0	2,449	3,447
2013	0	2,493	3,560
2014	0	0	3,631
2015	0	0	0

(1) The forecasted MECO numbers only represent the Island of Maui.

	Installed AMI Meters					
	HECO		MECO		HELCO	
	AMI	Non-AMI	AMI	Non-AMI	AMI	Non-AMI
(1) 2009	520	2209	0	(2) 780	0	1295

(1) Includes all meters currently installed on 4/30/09 that were installed 1/1/09 through 4/30/09

(2) Only the Island of Maui is included in the MECO meter count.

CA-IR-24

Ref: Meter Installation.

a. Based on the assumption that, other than customers who have had AMI meters installed for purposes of pilot testing, all other AMI meter installations have been made as a result of a customer request, please discuss whether, if a customer affirmatively opts-out of the utility time-of-use tariff, that customer's decision to opt out circumvents some, if not many, of the possible benefits thought to be achievable through the implementation of AMI meters.
b. Please discuss whether the Company has established and conducted any type of survey that gathers customer responses regarding the reasons why AMI meter installation was requested but TOU rates were not accepted. If so, please provide the results of the survey.

HECO Companies' Response:

a. There have not been any AMI meter installations made as a result of a customer request; all installations to date have been for the purpose of pilot testing. Nevertheless, the choice of the customer to opt-out of the time of use ("TOU") rate will not eliminate the rest of AMI's benefits. In such "opt-out" cases, knowledge of electricity usage will still provide the customer with an important tool to manage the time and level of electricity usage.
b. Not applicable. See the response to part a. above.

CA-IR-25

Ref: AMI Network.

HECO *indicates that its AMI network design "fosters overlapping coverage in order to achieve* signal redundancy" and that the design is based on achieving a coverage ratio of 1.5. (application, page 22).

a. Please discuss whether HECO relied upon any studies or analyses to determine that a coverage ratio of about 1.5 is reasonable. Please provide a copy of any such study, report or analysis.
b. If not already discussed in the response to part a. above or in a report or study, if provided, please discuss whether the ratio of 1.5 is reasonable for the various geographical conditions that exist on each of the islands served by the Companies. Please provide a copy of the analysis, study or reports relied upon to support the Companies' response.
c. Please discuss whether the Companies have any analyses, studies or reports that conduct a sensitivity analysis of the various possible coverage ratios and the impact on AMI network reliability and cost effectiveness. If so, please provide a copy of any such report, especially if it is specific to the geographical areas served by the Companies.
d. If no such analyses have been conducted, please discuss why it is reasonable to assume that a 1.5 coverage ratio is reasonable as opposed to some other value that might result in a lower cost but negligible decrease in reliability or increased reliability but at a negligible increase in cost.

<u>HECO Companies' Response:</u>

a. Under the terms of the Sensus Agreement ("Agreement"), Sensus will be the owner and operator of the RF network and will be responsible for meeting the performance requirements contained within the Agreement. Sensus modeled the AMI Network's coverage, which is shown in Exhibit D of the Agreement. Exhibit D establishes the geographic coverage requirement that Sensus must meet for each of the Companies under the terms of the Agreement. Based on experience, Sensus uses an average coverage ratio of 1.5 as an input variable to their design model. Regardless of the actual coverage ratio for the Tower Gateway Basestations ("TGBs"), Sensus is obligated under the Agreement to meet very specific network performance criteria that will be monitored and reviewed with Sensus on a routine basis throughout the term of the Agreement.

b. The development of the Sensus Network model is an iterative process which includes many input criteria such as optimal coverage ratio, distribution of meters, terrain, clutter, and size and frequency of transmissions. Although TGBs have high output power and relatively long range, TGB installation sites must be carefully selected and such sites are typically at high elevations in order to properly leverage the TGB design. Sensus surveyed each island and developed a list of potential TGB sites. The selected TGB sites are listed in Exhibit D of the Agreement on pages 4, 15 and 20 (HECO, MECO and HELCO respectively). Sensus then used a proprietary modeling tool to evaluate each potential TGB site to determine the probable extent of AMI network coverage.

c. Sensus' objective in an AMI network design is balance the number of TGB sites against the need to ensure reliable network operations. Sensitivity analysis predicated on RF overlap ratios is not realistic due to the limitation on potential TGB sites. The more practical approach is to vary the number of TGB sites and antenna segmentation using multiple TGBs at the same site(s), based on knowledge of potentially (but not guaranteed) TGB sites. A useful example is the use of only 3 TGB sites with 3 TGBs on Maui in comparison to 7 TGB sites with 7 TGBs on the island of Hawaii. From a network coverage standpoint, the terrain of Maui can be viewed as "easier" but in both cases, geographic areas exist which would not have good AMI network coverage. The RF model design is set forth in Exhibit D of the Sensus Agreement.

d. See the Companies responses to a, b, and c. As the designer, owner, and operator of the AMI network, it is in the best interest of Sensus to minimize capital and O&M costs of the AMI network. The Companies' relied on Sensus to properly design the AMI network and the Agreement provides assurance that Sensus will deliver the required performance over the term of the Agreement.

CA-IR-26

Ref: AMI and Non-AMI Meters.

a. The Companies indicate that the expected life of the AMI meters is 15 years in footnote 31 (application, page 21). Please provide the basis for this assertion, including, but not limited to, any copies of studies or analyses.
b. Please provide the average useful life of the non-AMI meters currently in service.
c. The Companies are requesting accelerated cost recovery of the AMI meters and the remaining net book value for replaced non-AMI meters. Please provide copies of any communications from rating agencies or other sources that specifically indicate that without accelerate cost recovery of these costs, investors will assume that there is less certainty regarding the recovery of their investments and that regulatory support for the initiative is uncertain.
d. Please provide examples of the journal entries that would be required to reflect the appropriate accounting for the proposed accelerated depreciation of the AMI meters and recovery of the replaced non-AMI meters in conjunction for ratemaking purposes with the continued use of currently approved depreciation rates for book purposes.
e. If not already reflected in the response to part d. above, please confirm that, if the Companies' proposal is approved, there will be a deferred balance that will be reflected as an offset to rate base since the Companies will recover the costs of the AMI on an accelerated basis, but its books will still reflect some balance related to those assets. Please provide illustrative examples of the Companies' financial and regulatory accounts that reflect the Companies' proposed accounting treatment.

HECO Companies' Response:

a. Without definitive test data from Sensus Metering Systems, Inc ("Sensus"), the Companies' AMI vendor, the Companies relied on their limited Sensus piloting experience to evaluate the AMI meter failure rates. The Companies expect the life of the Sensus AMI meters to be approximately 15 years. Other utilities, such as PG&E and SCE[1] have taken the position that the expected life of an AMI meter is 20 years and this has been supported by the California Public Utilities Commission. The financial model accounts for the minority of the AMI meters that fail. The expected life of the AMI meter has significant implications on the economic viability of the AMI project. Longer

[1] www.sce.com/NR/rdonlyres/B8B338D4-A893-4269-98F0-DF296628170/0/Vol3_Testimony_AMIPhaseIIApplication.pdf

expected life assumptions could be employed in the Companies' financial model if this is supported by detailed test data from Sensus (and Elster[2]). It should be noted that the Sensus meter warranty, as stated in Section 2(d) of the Sensus Agreement is limited to the first of "*18 months from delivery*" or "*12 months after installation*". Therefore, the availability of test data on the specific meters to be deployed by the Companies is important. The Companies expect Sensus to perform testing on the specific meters that will be employed by the Companies in the AMI project. This testing would include accelerated life cycle testing by Sensus and could also include parallel testing by HECO through a qualified, third party testing organization.

b. The average useful life embedded in the Companies' most current depreciation rate for meters is 30 years.

c. The Companies have not received direct communications from rating agencies or other sources which have specifically indicated that, without accelerated cost recovery, investors will assume that there is less certainty regarding the recovery of their investments and that regulatory support for the initiative is uncertain. While there have been no direct communications from Standard & Poor's ("S&P") regarding investors' perceptions of risk associated with an accelerated cost recovery mechanism, S&P's view is that regulatory support for mechanisms which provide for timely cost recovery and help address the issue of regulatory lag is supportive of utility creditworthiness. For example, S&P has stated that, "For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when

[2] Elster provides the base commercial and industrial meter and integrates the Sensus FlexNet radio board.

a utility engages in a sizable capital expenditure program."[3] With respect to the importance of innovative recovery mechanisms on credit quality S&P has stated that, "we believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality." S&P goes on to say, "we believe that from credit perspective, management must work to limit uncertainty in the recovery of a utility's investment. In addition, we believe it must address the issue of rate case lag, especially when engaged in a sizable capital expenditure program. A regulatory jurisdiction that recognizes the importance of cash flow in its decision making process enhances the utility's creditworthiness."[4]

While S&P does not specifically address investors' perceptions or the impact on credit quality as a result of an accelerated cost recovery mechanism, it does address the importance of limiting uncertainty in the recovery of utility investments. An AMI surcharge with an accelerated cost recovery mechanism would enable the Companies to begin recovering their investment much more quickly than waiting for recovery in a rate case proceeding, with a longer recovery period. This accelerated recovery mechanism would serve to mitigate the risks and limit the uncertainty in the timeliness of recovery of the Companies' investment, as well as allow for improved cash flow. To a lesser extent, in conjunction with the AMI surcharge, the accelerated recovery mechanism would also limit the issue of regulatory lag. These are all factors cited by S&P which may help mitigate a potential degradation in credit quality.

[3] Standard & Poor's, "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry", November 26, 2008. (See Attachment 3)
[4] Standard & Poor's, RatingsDirect, "Recovery Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings", March 9, 2009. (See Attachment 4)

d. See Attachment 1 to this response for journal entries for non-AMI meters. See the Companies' response to CA-IR-36 for journal entries related to AMI meters.

e. Confirmed. See Attachment 2 to this response for an illustration of the accounting for the proposed accelerated recovery of the non-AMI meters and its impact to rate base.

AMI Docket 2008-0303
CA-IR-26, part d.
Attachment 1
Illustrative Example - Required Journal Entries to Account for Accelerated Cost Recovery of Non-AMI Meters

The journal entries below reflect the accounting treatment of the surcharge revenues related to the recovery of the existing non-AMI meters, existing non-AMI meters (until removed), and the removal of the non-AMI meters. Note, in practice, some of these entries may be combined and recorded at net. However, for the purposes of illustrating the accounting treatment, these entries are shown individually.

Entry No. 1:
This monthly entry will be automatically posted, via batch entry, by the Company's ACCESS system. Revenues are recorded as the surcharge is applied to the customer's bills.

Debit: Customer Billed Receivables
Credit: AMI Surcharge Revenues - Recovery of Non-AMI Meters NBV

Entry No. 2:
This monthly entry will be manually recorded to setup the regulatory liability related to the commencement of the AMI surcharge to recover the net book value, as of the date of the PUC approval in this docket, of the non-AMI meters.

Debit: AMI Surcharge Revenues - Recovery of Non-AMI Meters NBV
Credit: Regulatory Liability - Recovery of Non-AMI Meters NBV

Entry No. 3:
This monthly recurring entry is automatically posted to record the depreciation expense on existing non-AMI meters that have not yet been replaced. The depreciation expense will be based on the existing PUC approved depreciation rates in effect and applied to the non-AMI meters that have not yet been replaced.

Debit: Depreciation Expense
Credit: Accumulated Depreciation

Entry No. 4:
This entry will be manually recorded to recognize AMI surcharge revenues and reduce the regulatory liability (that has been set-up in Entry No. 1) for the depreciation expense of the non-AMI meters that have not yet been replaced. The amounts of this entry will be the same as Entry No. 3.

Debit: Regulatory Liability - Recovery of Non-AMI Meters NBV
Credit: AMI Surcharge Revenues - Recovery of Non-AMI Meters NBV

Entry No. 5:
This entry will be used to record the removal of the non-AMI meters upon replacement with a new AMI meter, including its related accumulated depreciation. The net book value of the removed non-AMI meters will reduce the regulatory liability (that has been set-up in Entry No. 1).

Debit: Accumulated Depreciation (on meters that are being removed)
Debit: Regulatory Liability - Recovery of Non-AMI Meters NBV
Credit: Non-AMI Meters

Docket 2008-0303
-IR-26, part e.
Attachment 2
Illustrative Example - Accelerated Cost Recovery of Non-AMI Meters

Assumptions:

Non-AMI meter costs	[A]	1,200,000	(12/31/2009)
Accumulated depreciation		450,000	(12/31/2009)
Net book value		750,000	(12/31/2009)
Non-AMI meter annual depreciation rate	[B]	3.50%	
Date receive PUC approval		12/31/2009	
Year surcharge commencement		2010	
Accelerated recovery - years		3	(2010, 2011, 2012)
Annual surcharge revenues		250,000	(2010, 2011, 2012)
Date AMI meter deployment		2011	
Years to deploy AMI meters (evenly)	[C]	3	

Non-AMI Meter Costs:

		12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	Total
Beg of year: Non-AMI meter costs	[D]	1,200,000	1,200,000	1,200,000	800,000	400,000	
REMOVED: Non-AMI meter costs (beg 2011)	[E]=[A]/[C]	-	-	(400,000)	(400,000)	(400,000)	
End of year: Non-AMI meters		1,200,000	1,200,000	800,000	400,000	-	
Beg of year: accumulated depreciation	[F]	408,000	450,000	492,000	356,000	192,000	
Depreciation on remaining non-AMI meters	[G]=[B]*[D]	42,000	42,000	42,000	28,000	14,000	
OVED: Acc Depr (beg 2011)	[H]=-([F]+[G])/[I]	-	-	(178,000)	(192,000)	(206,000)	
of year: accumulated depreciation		450,000	492,000	356,000	192,000	-	
Remaining AMI meter deployment - years	[I]	3	3	3	2	1	

Ratebase Impact of Non AMI Meters:

		12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	Total
Surcharge rev (recover $750K NBV beg 2010)		-	250,000	250,000	250,000	-	750,000
Less: Depreciation expense	[G]	-	42,000	42,000	28,000	14,000	126,000
Less: NBV of non-AMI meters removed	[E]-[H]	-	-	222,000	208,000	194,000	624,000
Annual regulatory liability impact - Inc(Dec)		-	(208,000)	14,000	(14,000)	208,000	-
Deduct from ratebase:							
Regulatory liability (collections > depr/removals)		-	(208,000)	(194,000)	(208,000)	-	-
Ratebase for non-AMI meters:							
NBV of remaining non-AMI meters		750,000	708,000	444,000	208,000	-	

STANDARD & POOR'S

My Credit Profile
Hawaiian Electric Industries Inc., HI - 'BBB/Stable/A-2'

Table of Contents

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

Publication date: 26-Nov-2008
Primary Credit Analyst: Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com

Standard & Poor's Ratings Services' analytic framework for companies in all sectors, including investor-owned utilities, is divided into two major segments: The first part is the fundamental business risk analysis. This step forms the basis and provides the industry and business contexts for the second segment of the analysis, an in-depth financial risk analysis of the company.

An integrated utility is often a part of a larger holding company structure that also owns other businesses, including unregulated power generation. This fact does not alter how we analyze the regulated utility, but it may affect the ultimate rating outcome because of any higher risk credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Relationship Between Business And Financial Risks

Prior to discussing the specific risk factors we analyze within our framework, it is important to understand how we view the relationship between business and financial risks. Table 1 displays this relationship and its implications for a company's rating.

Table 1 | Download Chart Data

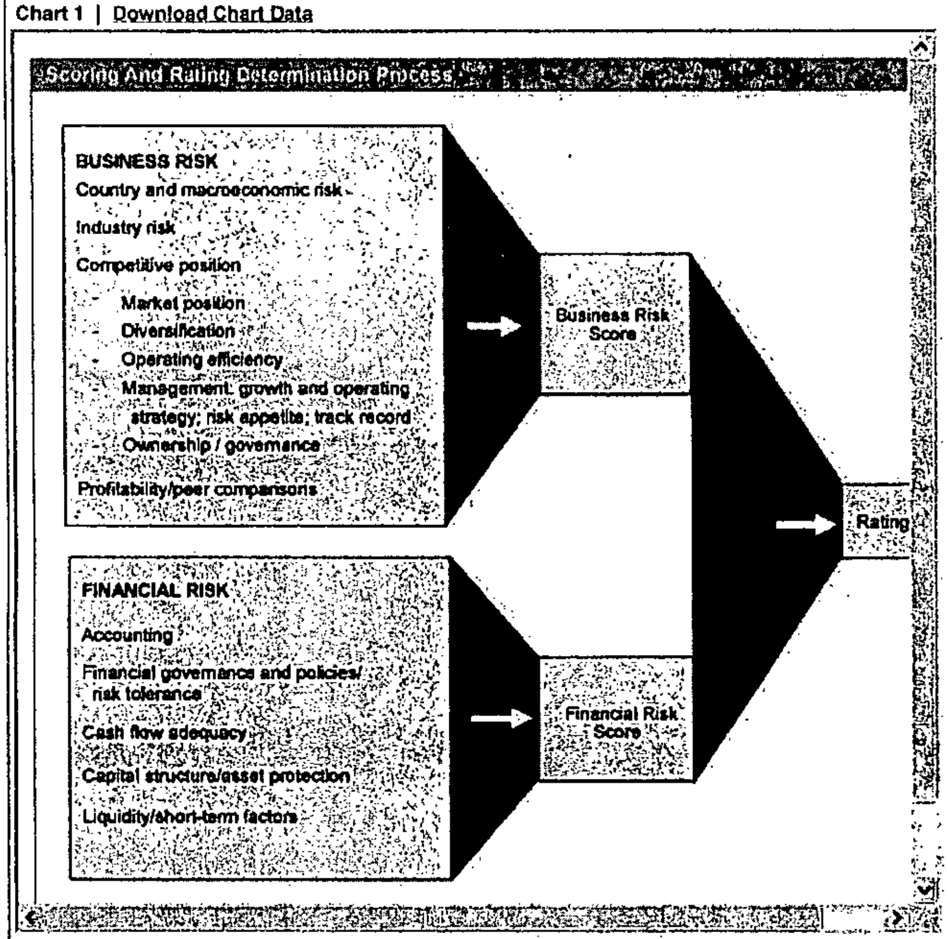
Business And Financial Risk Profile Matrix

Business Risk Profile		Financial Risk Profile: [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		(AAA/AA)	(A)	(BBB)	(BB)	(B)
[illegible]	(AAA/AA)	AAA	AA	A	BBB	BB
[illegible]	(A)	AA	A	A-	BBB-	BB-
[illegible]	(BBB)	A	BBB+	BBB	BB+	B+
[illegible]	(BB)	BBB	BBB-	BB+	BB-	B
[illegible]	(B)	BB	B+	B+	B	B-

These rating outcomes are shown for guidance purposes only. Other qualitative and quantitative rating factors may override these measures.

Chart 1 summarizes the ratings process.

Chart 1 | Download Chart Data



Part 1--Business Risk Analysis

Business risk is analyzed in four categories: country risk, industry risk, competitive position, and profitability. We determine a score for the overall business risk based on the scale shown in table 2.

Table 2 | Download Table

Business Risk Measures

Description	**Rating equivalent**
Excellent	AAA/AA
Strong	A
Satisfactory	BBB
Weak	BB
Vulnerable	B/CCC

Analysis of business risk factors is supported by factual data, including statistics, but ultimately involves a fair amount of subjective judgment. Understanding business risk provides a context in which to judge financial risk, which covers analysis of cash flow generation, capitalization, and liquidity. In all cases, the analysis uses historical experience to make estimates of future performance and risk.

In the U.S., regulated utilities and holding companies that are utility-focused virtually always fall in the upper range (Excellent or Strong) of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

1. Country risk and macroeconomic factors (economic, political, and social environments)

Country risk plays a critical role in determining all ratings on companies in a given national domicile. Sovereign-related stress can have an overwhelming effect on company creditworthiness, both directly and indirectly.

Sovereign credit ratings suggest the general risk local entities face, but the ratings may not fully capture the risk applicable to the private sector. As a result, when rating a corporation, we look beyond the sovereign rating to evaluate the specific economic or country risks that may affect the entity's creditworthiness. Such risks pertain to the effect of government policies and other country risk factors on the obligor's business and financial environments, and an entity's ability to insulate itself from these risks.

2. Industry business and credit risk characteristics

In establishing a view of the degree of credit risk in a given industry for rating purposes, it is useful to consider how its risk profile compares to that of other industries. Although the industry risk characteristic categories are broadly similar across industries, the effect of these factors on credit risk can vary markedly among industries. Chart 2 illustrates how the effects of these credit-risk factors vary among some major industries. The key industry factors are scored as follows: High risk (H), medium/high risk (M/H), medium risk (M), low/medium risk (L/M), and low risk (L).

Chart 2 | Download Chart Data

Key Industry Characteristics And Drivers Of Credit Risk

	Utilities regulated	Competitive power	Oil & gas downstream	Autos	Airlines
Industry dynamics and competitive environment					
Industry cyclicality	M	H	H	H	H
Ease of entry	L	M/H	H	M/H	M/H
Product cycle/obsolescence	L	L	L	H	L
Level of product quality	L	L	M	H	M
Disintermediation/substitution	L	L	L	L/M	L
Competition/commoditization	L/M	H	M	H	H
Pricing inflexibility	M	H	M	H	H
Business model stability	M	M/H	L	L/M	M
Demographic trends	L	L	M	H	L
Growth and profitability					
Growth outlook	L	M	L	M/H	L/M
Profit margin pressure/outlook	M	M/H	M	M/H	H
Earnings volatility	M	M/H	H	H	H
Operating considerations and costs					
Technological risk/change	L	L	L/M	L/M	L/M
Cost efficiency pressures	M	H	M	H	H
Operating leverage	M/H	H	H	H	H
R&D costs	L	L	L	H	L
Energy cost sensitivity	H	H	H	H	H
Raw material cost sensitivity	H	H	H	H	L
Labor costs	M	M	M	H	H
Labor inflexibility/unrest	L	L	M	H	H
Pension costs/contingents	M	L	L/M	H	M/H
Environmental impact/costs	H	L	H	H	M/H
Marketing costs	L	L	M	H	L/M
Customer concentration	L	M	L	L	L
Supplier concentration	H	H	H	M	M
Risk management	M	H	M	M	M
Asset/plant quality and age/upkeep	M	H	H	M	M/H
Event risk sensitivity	M/H	H	H	M/H	H
Financial market volatility/sensitivity	M	M/H	L	M	M
Fashion/fads/design, brand risk	L	L	L	H	L/M
Capital and financing characteristics					
Capital intensity	H	H	H	H	H
Borrowing requirement	H	H	L/M	H	H
Interest rate sensitivity	L/M	L/M	L/M	H	L/M
Government, regulatory, and legal environments					
Regulation/deregulation	H	H	M	M/H	H
Government macroeconomic and social policies	H	H	H	H	M/H
Litigiousness/legal risk	L	H	M	M	M

Industry strengths:

- Material barriers to entry because of government-granted franchises, despite deregulatory trends;
- Strategically important to national and regional economies; key pillar of the consumer and commercial economy;
- Improving management focus industry-wide on operating efficiency in recent years; and
- Cross-border growth opportunities in Europe and industrializing emerging markets.

Industry challenges/risks:

- Maturity, with a weak growth outlook in developed countries;
- Highly politicized and burdensome regulatory (i.e., rate setting and investment recovery) process; and
- Risks of "legacy cost drag" as wholesale and retail markets move toward greater deregulation.

Major global risk issues facing the utilities industry:

- Increased volatility in the regulatory environment and competitive landscape leading to greater uncertainty regarding adequacy of pricing and return on capital;
- Longer-term impact of, and ability to absorb, significant secular upturn in fuel costs, which is the industry's major operating expense;
- Ability to recover massive investment costs that will likely be necessary to replace aging industry infrastructure in a harsher cost and regulatory environment; and
- The debate over global warming will continue far beyond 2008. What the ultimate outcome will be is unclear, but growing legislation addressing carbon emissions and other greenhouse gases is probable in the near future. Utilities' ability to recover environmentally mandated costs in authorized rates and consumers' willingness to pay them could impact the industry's future credit strength.

Industry business model and risk profile in transition

Regulated utilities are in many developed countries transitioning away from quasi-monopolies toward more open competitive environments.

The level of business and credit risk associated with the investor-owned regulated utilities has historically proven in most countries to be lower (risk) than for many other industries. This has been because of the existence of government policy and related regulation that created significant barriers to entry limiting competition, and regulatory rate setting designed to provide an opportunity to achieve a specific level of profitability. The credit quality of most vertically integrated utilities in developed countries has historically been, and remains, solidly investment grade. This, to reiterate, is primarily a function of the existence of protective regulation.

The risks of, and rationale for, deregulation

The traditional protected and privileged utilities industry business model with its marked monopolistic characteristics is in many countries undergoing transition to a more competitive and open framework. This transition process, known as deregulation or liberalization, is weakening the business and credit risk profile of the industry. While the impact of these changes may prove positive in the longer term for more efficient industry players, it is important to bear in mind that economic history is littered with the vestiges of industries and enterprises that once flourished under the protection of government-created barriers and other protections. The shift is being driven by introduction in many countries of policies to encourage the entrance of new competitors and to reduce the traditional regulatory protections and privileges enjoyed by incumbents. Historically, the regulated investor-owned utilities were usually granted exclusive franchises. Because of the significant risks associated with the capital-intense nature of the utility investment, including massive sunk/fixed costs and long-term break-even horizons, governments in many countries created legal and regulatory frameworks that granted exclusivity to one operator in a given geographic area. To offset the monopolistic pricing power this exclusivity created, a system of heavy regulation was typically developed, which included the setting of pricing. The model often set pricing on a "cost-plus-basis", i.e., the margin over cost allowing for a perceived fair return to shareholders of investor-owned utilities. One major weakness of this system is that it created little incentive for utilities to efficiently manage costs. In recent years as many governments have adopted more liberal open market economic philosophies and related policies focused on the creation of greater competition—in an effort to foster improved economic growth and pricing efficiency throughout the economy—the traditional utility models in many countries have come under increasing political scrutiny and pressure.

A major public policy and political risk, as well as a credit risk, associated with deregulation of protected industries, is that existing incumbents often experience significant challenges in readjusting their management strategies, cultures, and expense basis to be able to compete effectively in the new environment.

The turmoil and bankruptcies in the U.S. in the nonregulated power marketing and trading arena between 2000 and 2002 arose subsequent to a major government initiative to deregulate the wholesale market. These failures, as well as other high-profile problems arising from deregulation elsewhere in the world, have given governments pause as to the desirability of a headlong rush into deregulation. In the U.S., for example, there is currently little impetus to carry deregulation any further.

Regulation and deregulation in the U.S.

While considerable attention has been focused on companies in states that deregulated in the late 1990s and the early part of this decade, and the related consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

Fragmentation of original model emerges in the U.S.

- Traditional regulated, vertically integrated utilities (generation, transmission, and distribution);
- Transmission and distribution;
- Diversified;
- Transmission; and
- Merchant generation.

We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management, which are the two leading drivers of credit quality.

Deregulation in the U.S. creates a new volatile industry subsector

The birth of large-scale, nonregulated power generators created the opportunity--and the need--for companies to market and broker power. Power marketers, independent power producers, and unregulated subsidiaries of utility companies offer power-supply alternatives to other utilities in the wholesale market as well as to large industrial customers. Power marketing operations have been formed by energy companies (many with experience in marketing natural gas), utility subsidiaries, and independents. As with the gas industry, electric power marketers expected to develop an efficient market by straddling the gulf between electricity generators and their customers, who have become "free agents" in the newly competitive environment.

Deregulation creates tiering of industry, business and credit risk profiles in Europe

The regional differences in market liberalization across Western Europe result in material variations in industry and business risk profiles for the utilities industry at the national level. The U.K. and Nordic markets, in particular, are substantially deregulated and open, and consequently present higher risks than other markets that are less open, including France and the Iberian market. Ratings therefore generally are lower in these more deregulated markets. The less-liberalized markets may face more regulatory risk going forward, particularly if efforts by the EU to advance the internal market by increasing the extent of market liberalization across the EU continue.

Legal action against companies that infringe on competition laws should be expected--particularly against those that move to prevent new entry and limit customer choice (for example, through the tying of markets and capacity hoarding) or collude with other incumbents to do so. The European Commission (EC) can fine companies that have violated antitrust laws up to 10% of their global annual turnover and, under certain conditions, impose structural remedies. Particular emphasis would be placed on increasing the effective unbundling of network and supply activities and on diminishing market concentration and barriers to entry.

The EC has publicly stated is intention to pursue, as a priority, abuses of the dominant position of vertically integrated companies (called vertical foreclosure). Behavioral remedies, such as energy release programs, are expected to be imposed by the EC for which such abuses, or collusion, are proved. The commission could also enforce structural measures when behavioral remedies are deemed insufficient.

3. Company competitive position and keys to competitive success

In analyzing a company's competitive position, we consider the following:

- Regulation;
- Markets;
- Diversification;
- Operations;
- Management, including growth strategy;
- Governance; and
- Profitability.

We are most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations.

Regulation. Critical success factors include:

- Consistency and predictability of decisions;
- Support for recovery of fuel and investment costs;
- History of timely and consistent rate treatment, permitting satisfactory profit margins and timely return on investment; and
- Support for a reasonable cash return on investment.

Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Our evaluation encompasses the administrative, judicial, and legislative processes involved in state and national government regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case by case with regard to the potential effect on credit quality.

Evaluation of regulation focuses on the ability of regulation to provide utilities with the opportunity to generate cash flow and earnings quality and stability adequate to:

- Meet investment needs;
- Service debt and maintain a satisfactory rating profile; and
- Generate a competitive rate of return to investors.

To achieve this, regulation must allow for:

- Timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity;
- Ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract; and
- Ability to recover costs in new investment over a reasonable time frame.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise sometimes be a significant cash flow drain and reduces the utility's need to issue debt during construction.

Markets/market position. Critical success factors include:

- A healthy and growing economy;
- Growth in population and residential and commercial customer base;
- An attractive business environment;
- An above-average residential base; and
- Limited bypass risk.

The importance of diversification and size. Critical success factors include:

- Regional and cross-border market diversification (mitigates economic, demographic, and political risk concentration);
- Industrial customer diversification;
- Fuel supplier diversification;
- Retail, compared with wholesale;
- Regulatory regime diversification; and
- Generating facility diversification.

Operations (operating strategy, capability, and performance efficiency). Critical success factors include:

- Low cost structure;
- Well-maintained assets;
- Solid plant performance;
- Adequate generating reserves, and compliance with environmental standards; and
- Limited environmental exposures.

Management evaluation. Utilities are complex specialized businesses requiring experienced and successful management teams to have a strong mix of the aforementioned disciplines. Critical elements of management success include:

- Commitment to credit quality;
- Operating efficiency and cost control;
- Maintaining a competitive asset base, i.e., power plant construction project management, and plant upkeep and renovation;
- Regulatory track record, process, and relationship management;
- M&A experience in successfully identifying, executing, and integrating acquisitions;
- Credibility and strong corporate governance;
- Conservative financial policies, especially regarding non-regulated activities; and
- Ability and track record in repositioning and transforming business to not just survive, but prosper in a more open market environment.

Management is assessed for its ability to run and expand the business efficiently, while mitigating inherent business and financial risks. The evaluation also focuses on the credibility of management's strategy and projections, its operating and financial track record, and its appetite for assuming business and financial risk.

The management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, the impact of deregulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

We also focus on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

4. Profitability/peer comparison

Regulated. Traditionally, the lower levels of risk in utilities because of the highly regulated environment has resulted in lower profitability and return on capital than in many other industrial sectors. In the regulated marketplace the level and margin of profitability has often primarily been a function of regulatory leeway, with the contribution of operating efficiency and revenue growth taking more of a back seat.

Deregulated/liberalized environments. In deregulated markets, cost efficiency and flexibility, and internal growth, are the major profitability drivers. The development of a robust risk management culture and infrastructure are also keys to creating stability of earnings, because the company no longer has recourse to the regulator to cover costs or losses—a recourse that usually protects from downside earnings surprises in the regulated sector.

Whether generated by the regulated or deregulated side of the business, profitability is critical for utilities because of the need to fund investment-generating capacity, maintain access to external debt and equity capital, and make acquisitions. Profit potential and stability is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital also has a greater ability to fund growth internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets, as well. In fact, a company's profit performance offers a litmus test of its fundamental health and competitive position. Accordingly, the conclusions about profitability should confirm the assessment of business risk, including the degree of advantage provided by the regulatory environment.

Part 2—Financial Risk Analysis

Having evaluated a company's competitive position, operating environment, and earnings quality, our analysis proceeds to several financial categories. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios.

We analyze five risk categories: accounting characteristics; financial governance/policies and risk tolerance; cash flow adequacy; capital structure and leverage; and liquidity/short-term factors. We then determine a score for overall financial risk using the following scale:

Table 3 | Download Table

Financial Risk Measures

Description	Rating equivalent
Minimal	AAA/AA
Modest	A
Intermediate	BBB
Aggressive	BB
Highly leveraged	B

The major goal of financial risk analysis is to determine the quality of cash resources from operations and other major sources available to service the debt and other financial liabilities, including any new debt. An integral part of this analysis is to form an understanding of the debt structure, including the mix of senior versus subordinated, fixed versus floating debt, as well as its maturity structure. It is also important to analyze and form an opinion of management's financial policy, accounting elections, and risk appetite. Using cash flow analysis as a building block, it is further necessary to establish the company's liquidity profile and flexibility. While closely interrelated, the analysis of a company's liquidity differs from that of its cash flow as it also incorporates the evaluation of other sources and uses of funds, such as committed undrawn bank facilities, as well as contingent liabilities (e.g., guarantees, triggers, regulatory issues, and legal settlements).

1. Accounting characteristics

Financial statements and related footnotes are the primary source of information about a company's financial condition and performance. The analysis begins with a review of accounting characteristics to determine whether ratios and statistics derived from the statements adequately measure a company's performance and position relative to those of both its direct peer group and the universe of industrial companies. This assessment is important in providing a common frame of reference and in helping the analyst determine the quality of disclosure and the reliability of the reported numbers. We focus on the following areas:

- Analytical adjustments and areas of potential concern;
- Significant transactions and notable events that have accounting implications.
- Significant accounting and financial reporting policies and the underlying assumptions.
- History of nonoperating results and extraordinary charges or adjustments and underlying accounting treatment, disclosure, and explanation.

2. Financial governance/policies and risk tolerance

The robustness of management's financial and accounting strategies and related implementation processes is a key element in credit risk evaluation. We attach great importance to management's philosophies and policies involving financial risk.

Financial policies are also important because companies with more conservative balance sheets and the credit capacity to pursue the necessary investments or acquisitions gain an advantage. Overly aggressive capital structures can leave very little capacity to absorb unexpected negative developments and will certainly leave little capacity to make future strategic investments. Companies with the credit capacity to support strategic investments will be better positioned to both evolve with industry change and to withstand inevitable downturns.

Understanding management's strategy for raising its share price, including its financial performance objectives, e.g., return on equity, can provide invaluable insight about the financial and business risk appetite.

3. Cash flow adequacy

Cash-flow analysis is one of the most critical elements of all credit rating decisions. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash-flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Focusing on the source and quality/volatility of cash flow is also important (e.g., regulated/deregulated; generation/transmission/trading).

A review of cash flow historically, as well as needs on a forward-looking basis, should take into account levels of capital expenditures for new generation plants. In periods where elevated new construction occurs in anticipation of a rise in power demand, cash outflows will be high.

It is particularly important to evaluate capital-intensive businesses, such as utility companies, on the basis of how much cash they generate and absorb. Debt service is an especially important use of cash flow.

Cash-flow ratios. Ratios show the relationship of cash flow to debt and debt service, and also to the company's needs. Because there are calls on cash flow other than repaying debt, it is important to know the extent to which those requirements will allow cash to be used for debt service or, alternatively, lead to greater need for borrowing. The most important cash flow ratios we look at for the investor-owned utilities are:

- Funds from operations (FFO)/Total debt;
- FFO/Income;
- Funds from operations/Total debt (adjusted for off-balance-sheet liabilities);
- EBITDA/Interest; and
- Net cash flow/Capital spending requirements.

4. Capital structure and leverage

For utilities, the long-term nature of capital commitments and extended breakeven periods on investment, make the type of financing required by these companies to finance these needs to be similar in many ways to the financing needs of other long-term asset-intensive businesses. Our analysts review projections of future CAPEX, debt, and FFO levels to make a determination of the likely level of leverage and debt over the medium term, and the companies' ability to sustain them. The valuation of the debt amortization scheduled is tied into projections of profitability breakeven, and the underlying assets becoming cash-flow-positive, are key components of the combined cash flow and leverage analysis.

Capitalization ratios. When analyzing a utility's balance sheet, a key element is analysis of capitalization ratios. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt. Companies with strong balance sheets will have more flexibility to further reduce their debt, and/or increase their dividends. The following are useful indicators of leverage:

- Total debt*/total debt + equity; and
- Total debt* + off-balance-sheet liabilities/total debt + off-balance-sheet liabilities + equity.

*Power purchase agreement-adjusted total debt. Fully adjusted, historically demonstrated, and expected to consistently continue.

Debt leverage, and interest and amortization coverage ratios are the key drivers of the financial risk score.

5. Liquidity/working capital/short-term factors:
Our liquidity analysis starts with operating cash flow and cash on hand, and then looks forward at other actual and contingent sources and uses of funds in the short term that could either provide or drain cash under given circumstances.

A key source of liquidity is bank lines. Key factors reviewed are total amount of facilities; whether they are contractually committed; facility expiration date(s); current and expected usage and estimated availability; bank group quality; evidence of support/lack of support of bank group; and covenant and trigger analysis. Financial covenant analysis is critical for speculative-grade credits. We request copies of all bank loan agreements and bond terms and conditions for rated entities, and review supplemental information provided by issuers for listing of financial covenants and stipulated compliance levels. We review covenant compliance as indicated in compliance certificates, as well as expected future compliance and covenant headroom levels. Entities that have already tripped or are expected to trip financial covenants need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications to covenants. Tripping covenants can have a double negative effect on a company's liquidity. It may preclude it from borrowing further under its credit line, and may also lead to a contractual acceleration of repayment and increased interest rates.

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Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings

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Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings

Credit markets are tight. Liquidity is constrained. And construction, labor, and material costs are soaring. As if that weren't enough, the U.S. electric utility sector also faces aging infrastructure, declining capacity margins, and increasing environmental compliance requirements. To the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures. Although construction expenditure forecasts are temporarily lower due to deferrals of some projects, future spending needs will still be significant, especially in light of environmental requirements. And regulatory commissions reviewing material rate increase requests during a time of exceptional economic hardship might be very reluctant to approve higher electric base rates for consumers (as has occurred in Illinois, Michigan, and New York).

For these reasons, we believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality. That's why Standard & Poor's Ratings Services views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness.

Regulatory Risk

Regulators have historically set electricity rates that allow utilities to recover their operating costs and earn returns on equity. In our view, a key to the utility's credit quality is a strong, collaborative, and effective working relationship among management, regulators and, increasingly, elected officials to comprehensively vet and understand the risks associated with the utility's recovery of its investment. If the recession extends well into 2010, it is likely to have a credit drag on the sector, especially if utilities come under the inevitable cost scrutiny by regulators. Management's ability to manage this regulatory risk is a critical skill set.

Key factors in our analysis of the regulatory risk are the regulator's track record of consistency, stability, and predictability, as well as efficiency and timeliness. While we recognize the potential economic and political consequences of attempting to significantly raise utility rates during a recession, we believe that from credit perspective, management must work to limit uncertainty in the recovery of a utility's investment. In addition, we believe it must address the issue of rate case lag, especially when engaged in a sizable capital expenditure program. A regulatory jurisdiction that recognizes the importance of cash flow in its decision making process enhances the utility's creditworthiness.

Upon completion of a major project, while a phase-in or rate moderation plan may lessen the burden on the consumer and be more acceptable during an economic downturn, it may impair the utility's credit quality. Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs. In turn, this may necessitate a larger bank line that increases borrowing costs or increases debt levels to term out the short-term borrowings with medium-term notes, potentially increasing pressure on a company's financial profile. Hence, delayed revenue recovery is likely to be clearly more risky than traditional ratemaking treatment or rate mechanisms that provide timely rate recognition.

In our view, there are ratemaking alternatives that can eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in an onerous construction program. Instead of significantly large base rate increases or lengthy rate moderation or phase-in plans, separate tariff provisions that allow for timely rate recognition during construction, without requiring a utility to file a formal rate case application, can gradually ease higher costs into rates, limiting the accumulation of financing costs. Such provisions can also enhance cash flow and earnings stability.

Don't Forget The Fuel

Of primary importance to rating stability is limiting exposure to variations in fuel and purchased power costs, which constitute a utility's most significant expense. These expenses are largely out of utility management's control. Utilities that operate under rate moratoriums, fixed-fuel mechanisms, or significant regulatory lag, or without fuel and purchased-power adjustment clauses, are at risk for fluctuations in fuel and purchased power costs. As a result, they may be subject to reduced operating margins, and greater cash flow volatility and demand for working capital. Companies that are granted fuel true-ups may be required to stretch out recovery over many years to ease the pain for the consumer. There is no guarantee at some distant future date that collection of deferred revenues will occur. Changes in regulators, elected officials, and the economics of the service territory may render the promised recovery less certain.

Standard & Poor's notes that fuel adjustment clauses have become much more common in the utility industry, and several jurisdictions have recently reinstated previously abolished fuel clauses, but not all are created equal. While some states--such as Florida, Iowa, Kansas, and New York--permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions--such as Vermont and Washington State--impose deadbands in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. Cost recovery mechanisms that permit frequent updating of any estimated costs may help to keep any deferred balance to a relatively small amount.

Construction Is Accelerating

In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle. States such as Colorado, Idaho, Kansas, South Carolina (for nuclear facilities), North Dakota (for investments in transmission infrastructure and environmental compliance), and Wisconsin allow utilities to employ this credit-supportive ratemaking mechanism for certain projects. Allowing recovery of projected costs with subsequent periodic updates for actual results limits risk for fluctuating costs that occur between rate cases and reduces lags in cost recovery. Examples of less credit-supportive adjustment mechanisms include those that are triggered only after a company's incremental costs reach high thresholds (e.g. Washington) or those that, once triggered, force a company to accumulate significant deferrals before implementing a surcharge that results in real cash. Weak adjustment mechanisms may also cap accumulated deferrals or surcharges between rate cases.

In view of the risks associated with adding new base load capacity, utility managements are avoiding building facilities until absolutely necessary and only with binding regulatory assurances. From a credit perspective, we view the ability of the utility, commission staff, consumer advocates, and other major interveners to reach agreement on need, costs, and cost recovery before construction of new base load capacity as favorable. Iowa, Kansas, and Wisconsin have used preapproval or advance determination of the ratemaking principles for the recovery of certain investments, thereby potentially eliminating a large degree of uncertainty related to this issue.

An increasing number of regulatory jurisdictions are adopting tracking mechanisms and other riders that allow companies to adjust retail rates to reflect capital costs associated with environmental compliance equipment. These mechanisms eliminate the need to file a formal rate application to capture rate base additions and in many instances permit a return on, and of, capital on current and planned projects. Florida, Kansas, Indiana, Minnesota, and Texas are among those states that have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with emission controls.

Earnings and cash flow volatility potentially can be reduced and creditworthiness enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing extraordinary storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, we believe it has shown a willingness to work with utilities and has authorized increased charges to provide for the recovery of storm restoration expenses on a timely basis and to start replenishing storm reserves.

Rate mechanisms that mandate earnings sharing between shareholders and consumers compensate well run companies with a share of the profits when they earn more than their allowed return on equity. Accordingly, California has implemented an incentive framework that allows utilities to keep a portion of the net savings achieved under their energy efficiency programs. This gives an incentive to make the companies' operations more efficient. In some cases, sharing mechanisms also may provide downside protection to bondholders and can partially shield companies during troubled times by requiring consumers to foot the bill for a portion of lost earnings.

The ability to collect a consistent cash stream, regardless of a service area's weather conditions, provides an important level of stability. Several warmer-than-normal winters or cooler-than-normal summers could impair a utility's financial profile unless weather normalization measures are in place. Such protection can be achieved via a normalization clause or rate design. Some companies without such provisions have seen their financial profiles weaken partially in response to significant adverse weather conditions.

Some regulators and utilities want to significantly increase energy efficiency and conservation programs. Programs designed to separate earnings from delivered volumes (decoupling) can eliminate a current major disincentive for utilities to develop such conservation programs. Traditionally, when people use less electricity, utilities lose revenue. This would also theoretically align the interest of consumers and utilities by implementing innovative rate designs that would not discourage energy conservation and efficiency. For example, in 2008, the Massachusetts Department of Public Utilities issued a ruling that ordered utilities to pursue full decoupling in their next base rate case filings. The order is intended to encourage alternative energy resources and energy conservation and efficiency and to reduce costs without hurting a utility's bottom line.

There are a host of other rate mechanisms or special tariffs that regulatory jurisdictions apply to allow for timely recovery of costs including those associated with transmission, bad debt, property taxes, pensions, infrastructure or bare steel replacement, and legislatively mandated energy efficiency and renewable resource projects. Finally, the greater the percentage of a utility's rates that it recovers through fixed charges rather than volume-based charges, the greater the support for credit quality. And, given the current recession, the application of these various rate mechanisms and techniques, in our view, can be crucial in sustaining creditworthiness for the utility while potentially reducing the risk of evading significant rate increases or rate shock to the customer.

Note: Standard & Poor's recently published Assessments Of Regulatory Climates for U.S Investor-Owned Utilities (Nov. 25, 2008) has identified Alabama, California, Florida, Georgia, Indiana, Iowa, South Carolina, and Wisconsin, as those deemed 'more credit supportive', and Idaho, Kansas, and Kentucky among those 21 jurisdictions characterized as 'credit supportive'. We factored many of the aforementioned rate recovery mechanisms as well as other ratemaking and financial stability factors and political considerations into these assessments.

CA-IR-27

Ref: AMI Network Lease.

The Companies are seeking Commission approval of lease expenses for the Sensus-owned, two-way radio frequency network.

a. Please provide copies of all analyses or studies that evaluated the net revenue requirement differences between the various options that were available regarding the AMI network. These options should include, but not be limited to, leasing, owning and outsourcing the AMI network functions.
b. If the Companies did not conduct such an analysis, please explain why not.
c. If the Companies did not select the lowest cost alternative for the AMI network, please explain why not and provide any documentation that supports the Companies' response.
d. If not already explained elsewhere, compare and discuss the qualitative benefits and costs of leasing, owning and outsourcing the AMI network.

HECO Companies' Response:

a. The companies reviewed and evaluated the following three options for the Network costs:

Option A – Sensus owns, operates and maintains the AMI network

Option B – HECO owns and Sensus operates and maintains the AMI network

Option C – HECO owns, operates and maintains the AMI network

Option C was eliminated because HECO does not have sufficient in-house resources or the required knowledge to fully maintain and operate the AMI Network's specialized communications systems. The Companies estimated the costs for each network option and this information is provided as Attachment 1 to this response. Net revenue requirements calculations were not completed, as there would have been no changes to the estimated benefits in the various network options while the cost differences were significant.

b. Not Applicable.

c. To the Companies' knowledge, the Companies selected the lowest cost alternative for the AMI Network.

d. The costs for each network option are presented in Attachment 1. Some of the benefits and risks of each network option are described below:

Option A (Sensus owns, operates, and maintains):

Benefits:

- Removes potential fluctuations in the cost of operating and maintaining the equipment.
- Guarantees long-term network performance.
- System upgrades are included in the service fee.
- Minimizes requirements for specialized training and skills within the Companies.
- Minimizes de-mobilization costs at the end of the system life.
- Eliminates the need for the Companies to negotiate TGB site leases.

Risks:

- Long-term contract could prevent possible operational and maintenance costs savings.
- Requires long-term contract.
- Operational and billing impacts if the provider can not perform up to the requirements.
- No positive control over the equipment.
- Limited visibility into network operations.
- Limited knowledge by Companies' personnel in network operations.

Option B (HECO owns and Sensus operates and maintains):

Benefits:

- *Minimizes requirements for specialized training and skills within the* Companies.
- Shorter contract term.

Risks:

- De-mobilization costs to the Companies at the end of the system life.
- System upgrades present additional costs.
- Network performance risk lies with the Companies.
- Fluctuations in the cost of operating and maintaining the equipment.
- The Companies' equipment is located at non-Company facilities; site leases might be more expensive if the Companies had this responsibility.

Option C (HECO owns, operates and maintains):

Benefits:

- Shorter contract term.
- Direct control of maintenance and operations.

Risks:

- The Companies must invest in specialized training and skills and hire network operations personnel.
- De-mobilization costs to the company at the end of the system life.
- Network Upgrades present an additional cost.
- No long term performance guarantees.
- Potential variations in the cost of operating and maintaining the network equipment.
- Operational and billing impacts if the Companies can not properly and reliably operate and maintain the network.

Attachment 1 contains confidential information and is provided subject to the Protective Order filed on April 15, 2009 in this proceeding.

CA-IR-28

Ref: AMI Project Functions.

a. Please provide a comprehensive list of all functions that are expected to be available upon the successful and complete implementation of the proposed AMI project. Please include citations to any vendor or other documentation that supports the list of features.
b. For each of the identified features, please list the various factors or systems that will affect the availability of the feature or function. For instance, there may be a feature that only requires the AMI meter as compared to a feature that requires the AMI meter, MDMS, CIS and OMS.
c. For each of the identified features, please list each customer class that can directly benefit from that feature.

HECO Companies' Response:

a. Attachment 1 provides a comprehensive list of all functions that are expected to be available upon the successful and complete implementation of the proposed AMI project. The ability to achieve the listed functionality lies with three vendors: (1) Sensus Metering Systems Inc. ("Sensus") (2) the MDMS vendor and (3) the CIS vendor.

The Sensus Agreement (attached to the application as Exhibit E-AMI System Performance Specifications) provides Sensus' contractual guarantee for functionality of the AMI front-end system. For the MDMS vendor, HECO will specify software requirements that will provide the functionality identified in Attachment 1. HECO does not rely on the citations of the vendors to determine product capabilities. Instead, HECO relies on piloting, demonstrations and advice from HECO's expert consultants to develop an achievable list of AMI system functions that will be available upon the successful and complete implementation of the proposed AMI project. Examples of the expert consultant advice, which HECO has already shared with the Commission, include the presentations that Enspiria Solutions provided at the AMI Technical Workshop on April 30, 2009 (see Attachments 2 and 3).

b. Attachment 1 identifies the HECO systems that will be impacted by this capability.

c. Attachment 1 identifies the customer classes that can directly benefit from each feature. Nearly all of the features will benefit all customer classes.

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
1.1.1. General				
1. Support smart electric metering with potentially different software configurations and business rules for HECO, HELCO, and MECO.	Y	N/A	AMI, MDMS, CIS	All
2. Input, process, store, and analyze consumption, demand, and interval data from multiple AMI data collection systems.	Y	N/A	AMI, MDMS, Turtle, MVRS, MV90	All
a. Support net metering.	Y	N/A	AMI, MDMS, CIS	All
b. Support bidirectional metering.	Y	N/A	AMI, MDMS, CIS	All
3. Input, process, store, and analyze non-billing meter data such as pulse, voltage and power quality data as they are available from AMI.	Y	N/A	AMI, MDMS	All
4. Support schedule and on-demand meter reads and pinging of meter energized states by authorized users and by other HECO systems.	Y	N/A	AMI, MDMS, CIS, IVR	All
5. Support reading and pinging (for energized state) of pre-defined set of meters, hereby referred to as "virtual meters."	Y	Yes for OMS	AMI, MDMS, CIS, OMS, GIS	All
6. Support demand side reduction via integration with the HECO load management system to monitor and control programmable/controllable thermostats (PCT) and load control switches (LCS).	N	Y	AMI, MDMS, YUKON	All
1.1.2. Installation Support (Synchronization of installation data is with HECO meter installation vendor system and with CIS, pending final solution architecture design.)				
1. Support data synchronization among HECO information systems for meter provisioning and meter exchange data such as meter location, meter-site connectivity (meter to transformer connectivity), meter and communication module configuration, meter exchange reads, meter inventory, etc.	Y	N/A	AMI, MDMS, CIS, Meter Installation Tool	All
2. Support data synchronization among HECO information systems for Demand Response (DR) device installation and provisioning data.	N	Y	AMI, MDMS, YUKON	All
1.1.3. Data Repository				
1. Provide online data storage of register-reads, consumption, interval data, event data, and other meter data such as blink counts and voltage.	Y	N/A	MDMS	All

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
2. The system shall have built-in processes to archive/warehouse data to a lower cost storage media.	Y	N/A	MDMS	All
3. Facilitate online access to all data by authorized users and other HECO information systems and applications.	Y	N/A	MDMS, CIS	All
1.1.4. Meter Data Processing and Analysis				
1.1.4.1. Revenue Management				
1. Analyze meter tampering flags, power outages, and usage trends to find potential revenue protection issues and generate alerts and notifications automatically based on HECO configurable business rules.	Y	N/A	MDMS, REVPRO	All
2. Provide a user interface to support the analytics/investigation (i.e. view current and historical usage patterns) to valid suspected protection issues. Allow user to select for export the validated revenue protection issues.	Y	N/A	MDMS, REVPRO	All
3. Execute turn-on/turn-off service orders from CIS via "virtual disconnect" and automatically monitor the daily consumption threshold. Monitor these NCOP, "new/no customer on premise", or "consumption on vacant", (registered reads above HECO configurable thresholds without an active customer account) and automatically generate alerts and notifications.	Y	N/A	AMI, MDMS, CIS	All
4. Daily Consumption Verification. The consumption threshold may be set by consumption (kWh) or percentage of historical daily average. Different thresholds may be set for different customer and rate classes.	Y	N/A	MDMS	All
1.1.4.2. Totalization and Aggregation				
1. Capture and aggregate metering data from a specified number of arbitrary physical meters. Allow system and user access to the aggregated data as if the aggregation is from a meter (virtual meter). This capability will support consolidated load research, transformer load management, etc.	Y	OMS Latter	MDMS, GIS, CIS, OMS, SynerGEE	All
2. Totalize interval data across multiple sub-meters into one master meter prior to aggregating the consumption and demands into the appropriate TOU periods.	Y	N/A	MDMS, CIS	All
3. Support net metering, aggregate data for a specified number of service points or channels with the ability to totalize data across multiple channels of the same recorder ID.	Y	N/A	MDMS, CIS	All

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
4. Support bidirectional metering, provide the ability to totalize positive and negative meter read values across multiple channels of the same recorder ID separately.	Y	N/A	MDMS, CIS	All
1.1.4.3. Validation, Estimation, and Editing (VEE)				
1. Perform programmatic and HECO-configurable data integrity checks including for example sum check, time check, etc.	Y	N/A	MDMS	All
2. Perform data verifications for zero consumption, daily high/low consumption limits, hourly data spike checks etc.	Y	N/A	MDMS, CIS	All
3. Automate estimation and allocation routines based on HECO-configurable rules and historical data.	Y	N/A	MDMS	All
4. Allow manual editing of missing or estimated/allocated data.	Y	N/A	MDMS	All
5. Zero Consumption. The system shall identify any meter with no change in registration for a programmable number of days and periodically generate field service order requests as appropriate	Y	N/A	MDMS	All
6. Billing Cycle Verification. The system shall identify any meter with cumulative usage since the last bill greater than a programmable threshold and generate alerts/notifications. HECO will be able to set different programmable thresholds for different customer types and tariffs	Y	N/A	MDMS, CIS	All
7. Complex Daily and Billing Cycle Verification. The system shall perform the same checks for all daily and billing quantities including Time-of-Day/Use and load factor determinants.	Y	N/A	MDMS, CIS	All
1.1.4.4. Audit Trail				All
1. Store all raw data entry and data edits, including direct meter register reads, estimated, allocated, edited and otherwise derived data	Y	N/A	MDMS	All
2. The system shall track all meter data through its lifecycle from direct meter reads to billing determinants including automated estimations by the system and user edits.	Y	N/A	AMI, MDMS, CIS	All
3. The system shall maintain audit trail and versioning from register reads to derived billing determinants.	Y	N/A	MDMS	All
4. The system should issue notifications when it receives actual reads that were estimated in calculating the billing determinants already sent to CIS.	Y	N/A	MDMS, CIS	All

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
5. All data entries and changes shall be logged and time stamped. ID of the user who edited the data and a comment field shall be part of the log.	Y	N/A	MDMS	All
6. Support Sarbanes-Oxley compliance	Y	N/A	MDMS	All
1.1.5. Billing				
1.1.5.1. Scheduling of Billing Determinant Deliveries				
1. Schedule meter reads as needed for in-cycle billing reads, off cycle meter reads, and special reads for re-bills, etc.	Y	N/A	AMI, MDMS, CIS	All
2. The MDMS shall provide configurable business rules around the billing window regarding system behavior when billing determinants are missing. (.Extrapolate "plug to cycle", schedule on-demand reads, and issue field order requests to collect read data as necessary.)	Y	N/A	MDMS	All
3. The MDMS shall provide the capability to receive and respond to ad-hoc requests for off-cycle reads (that may include requests to perform a remote virtual or physical connect or disconnect).	Y	N/A	AMI, MDMS, CIS	Remote Disconnects limited to Residential Customers
4. The MDMS shall receive the status and associated error codes of the off-cycle read and/or connect/disconnect requests from RNI and notify the CIS of the status the request.	Y	N/A	AMI, MDMS, CIS	Remote Disconnects limited to Residential Customers
5. Calculate billing determinants on schedule or on request by authorized users via the user interface or by other HECO systems via an API.	Y	N/A	MDMS, CIS	All
1.1.5.2. Billing Determinant Calculation				
1. Calculate billing determinants for cumulative consumption and time-of-use rates by processing consumption reads, interval data and reads from cumulative virtual TOU registers calculated in the meter.	Y	N/A	AMI, MDMS, CIS	All
2. Support the processing of the above read data into Time of Use (TOU) billing determinants.				
a. TOU billing determinants shall include the following: – TOU consumption buckets (consumption used just for the bill cycle)				

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
– TOU cumulative consumption buckets (an absolute consumption incrementing from one bill cycle to the next).	Y	N/A	AMI, MDMS, CIS	All
b. The TOU cumulative consumption bucket billing determinants can be calculated from both interval data and reads from the meter from virtual absolute cumulative TOU registers calculated in the meter	Y	N/A	AMI, MDMS, CIS	All
c. Allow varying TOU specifications of weekdays, weekends, holidays and seasons for a given TOU definition	Y	N/A	AMI, MDMS, CIS	All
d. Allow HECO to configure multiple TOU options (e.g. the number and duration of TOU rate periods) by customer type, tariffs, and rates.	Y	N/A	AMI, MDMS, CIS	All
3. Support the processing of the read data into billing determinants to support potential future tariffs that includes critical peak rebate and load factor billing determinants for example.	Y	N/A	AMI, MDMS, CIS	All
4. The MDMS shall allow HECO to configure the conditions under which a billing determinant will be flagged as estimated or edited (for example, the number of intervals in a bill cycle that were estimated/edited needed for the system to label the billing determinant estimated/edited).	Y	N/A	MDMS, CIS	All
5. Allow view, print, and modify the aggregated data prior to billing	Y	N/A	MDMS, CIS	All
1.1.6. Meter Asset Management				
1. Monitor and identify meter diagnostic flags such as stop-meters and Sensus RNI specific checks (out of service, memory overflow, etc.) for automated event notifications.	Y	N/A	AMI	All
2. Track and maintain meter to module and module to network connectivity, meter and module configuration, firmware revisions, interval length, soft switch setting, PQ settings, etc.	Y	N/A	AMI, MDMS, CIS	All
3. MDMS to record configuration data from meter via AMI.	Y	N/A	AMI, MDMS	All
4. System to determine what meter configuration/switch setting is needed in response to rate change from CIS.	Y	N/A	AMI, MDMS, CIS	All
1.1.7. AMI System Management				

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
1. Automatically generate notifications based on diagnostic events from the AMI system and HECO configurable business rules.	Y	N/A	AMI, MDMS	All
2. Track assignment, status, and resolution of AMI system problems via integration with HECO CIS (or the AMI vendor system).	Y	N/A	AMI, MDMS	All
3. Capture and track resolution of data exceptions, product problems and failures, etc.	Y	N/A	AMI, MDMS	All
4. Collect AMI system performance data, trend performance over time, and generate reports – response time (e.g. seconds/ping, seconds/on-demand read, interval data read availability, etc.	Y	N/A	AMI, MDMS	All
1.1.8. Customer Service Support				
1. Provide an internal customer service with a web application to access to current and historical consumption and interval data.	Y	N/A	MDMS, vignette	All
2. Allow the internal customer service user to search for the consumption, interval and billing determinant data via numerous mechanisms such as account number, meter number, customer name.	Y	N/A	AMI, MDMS, vignette, CIS	All
3. Support requests for on-demand reads.	3	3		
a. Provide a graphical user interface for users to select a meter and display one of the following at the option of the user: (i) the most current reads with timestamp available in MDMS, (ii) the reads with timestamp available in MDMS that are closest to a specified date and time, (iii) the historical reads with timestamps within the specified date period, or (iv) getting the current reads via the AMI system.	Y	N/A	AMI, MDMS, vignette, CIS	All
1.1.10. Outage Management Support				
1. Support requests for on-demand pinging of meters from users directly or from other HECO applications such as CIS and OMS to determine the energized state of the meter.	Y	N/A	AMI, MDMS, OMS Latter	All
a. Provide a graphical user interface for users to specify a set of one or more meters for pinging and display the ping results.	Y	N/A	AMI, MDMS, OMS Latter	All
b. Check if a restoration event of the same meter has been received from the meter.	Y	N/A	AMI, MDMS, OMS Latter	All

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
2. Process meter outage notifications (last gasps), timestamp/record/store the events, and relay the messages to another application such as OMS based on HECO configurable business rules, including the following:				All
a. Filter known distribution outages.	Y	N/A	AMI, MDMS, IVR, CIS, OMS Latter	All
b. Filter known service orders by querying the CIS database.	Y	N/A	AMI, MDMS, IVR, CIS, OMS Latter	All
c. Filter momentary outages with a HECO configurable time duration.	Y	N/A	AMI, MDMS	All
d. Throttle the messages to OMS.	N	Y	AMI, MDMS, OMS Latter	All
3. Process meter restoration events, timestamp/record/store the events, and relay the messages to another application such as OMS within the following response times from the time when the events are received from AMI.	N	Y	AMI, MDMS, OMS Latter	All
4. Meter Blink Counts – MDMS will process blink count events from AMI on daily basis and allow access to data for Power Quality analysis.	Y	N/A	AMI, MDMS, SynerGEE	All
1.1.11. Planning and Engineering Support				
1. Support load profile analysis and display for any user specified virtual meter or set of virtual meters. This data can be exported to a common file format such as Excel and Access.	Y	N/A	AMI, MDMS, SynerGEE, GIS	All
2. Support "system load snapshot" by collecting meter reads at a user specified date and time. These meter reads can be exported to a common file format such as Excel and Access.	Y	N/A	AMI, MDMS, SynerGEE, GIS, CIS	All
3. Allow access and export in common file format (e.g., Excel and Access) other AMI meter data such as voltage and power quality, blink counts, etc.	Y	N/A	MDMS	All
1.1.12. Load Research and Demand Response Support				
1. Provide user interface for selection of load profiles for display by season and day type (weekday, weekend, holiday, etc.), or any set of dates, and by rate class, customer type, or any user specified collection of meters (by route, by zipcode, by external file, etc.)	Y	N/A	MDMS	All

	Within AMI Project	Potential latter	Potentially Impacted Systems	Impacted Customers
2. Allow the user to export the raw and processed load profile data to a common file format such as Excel, Access, comma delimited file, etc.	Y	N/A	MDMS	All
3. Allow the correlation with events (such as account activation/deactivation, load control event, critical peak event, etc.) in the above functions (display and data export).	N	Y	MDMS, Yukon	All
4. Estimate customer baseline loads for calculating Demand Response billing determinants (e.g. critical peak rebate) based on historical load data for configurable number of "like-days." An example of the baseline calculation is included in Appendix X.	N	Y	MDMS, Yukon, CIS	All
1.1.13. Web Applications: Online Presentment, and Rate Analysis				
1. Allow HECO customers access to most-recent and historical usage in graphical and tabular forms. Objective is to allow consumers to view and understand their hourly energy usage patterns.	Y	N/A	MDMS, vignette	All
a. Overlay data streams for comparison purposes such as comparing hourly consumption with temperature. (MDMS shall store historical weather data or directly access the data from an external weather data source.)	Y	N/A	MDMS, vignette	All
b. Overlay the load data with TOU times and critical peak events.	N	Y	MDMS, vignette, Yukon	All
c. Show electric consumptions since the last bill.	Y	N/A	MDMS, vignette	All
2. Rate Analysis. Allow users to analyze effects of customer energy usage patterns and different rate programs, including for example, time of use, critical peak rebate, pre-pay, etc.	N	Y	MDMS, CIS	All

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to Real Problems

MDMS

Meter Data Management System

Jim Ketchledge

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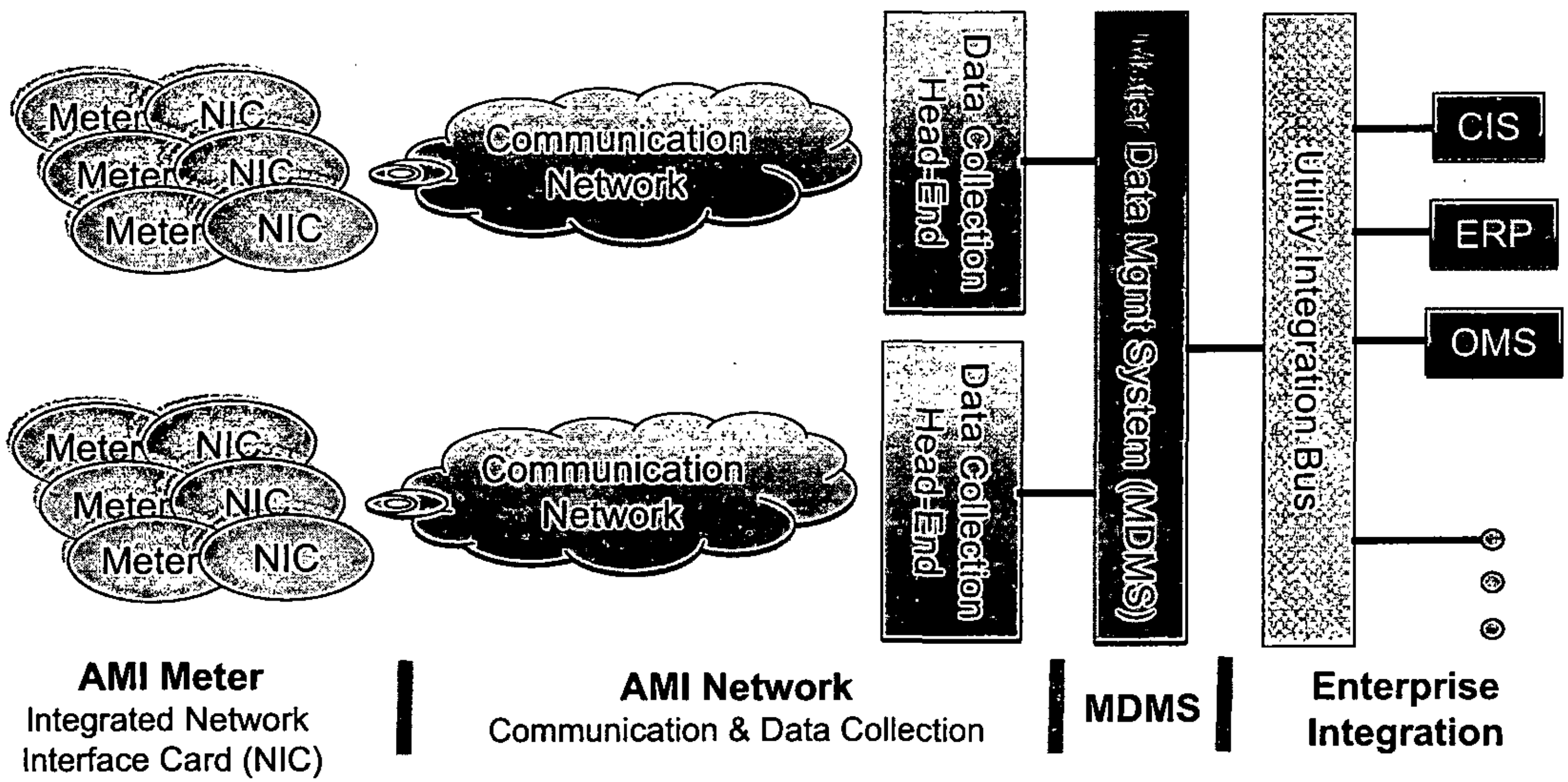
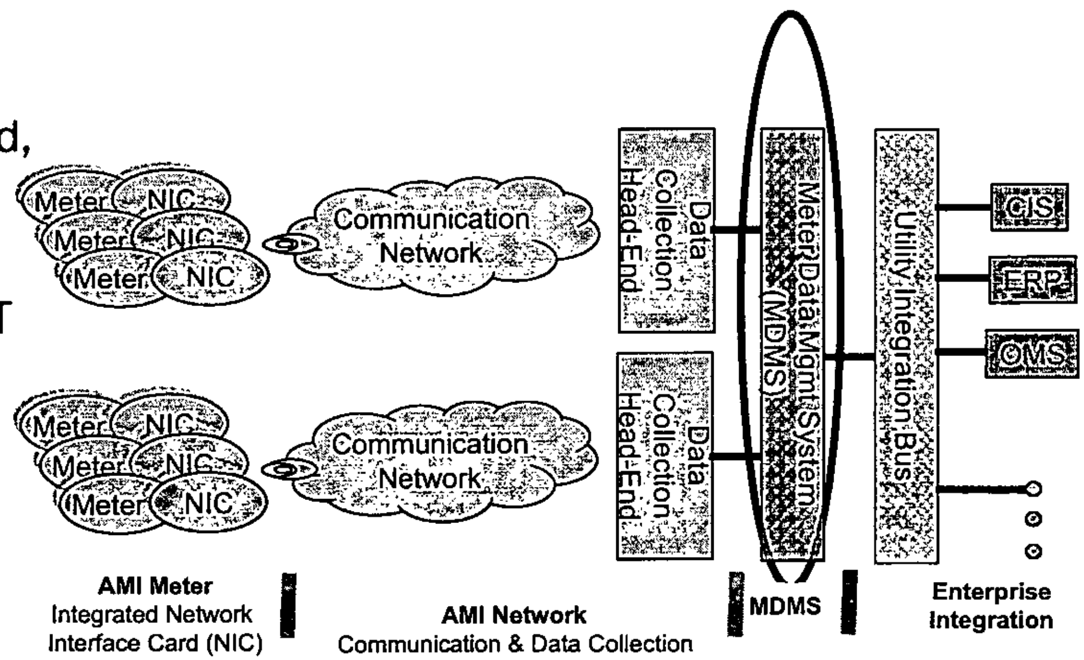
AMI System + Interfaces



What is MDMS?

- MDMS —"Meter Data Management System"
- Manages large volumes of meter data generated from AMI systems
- Data is collected, validated, and stored in a central data repository
- Available for other Utility IT systems to use



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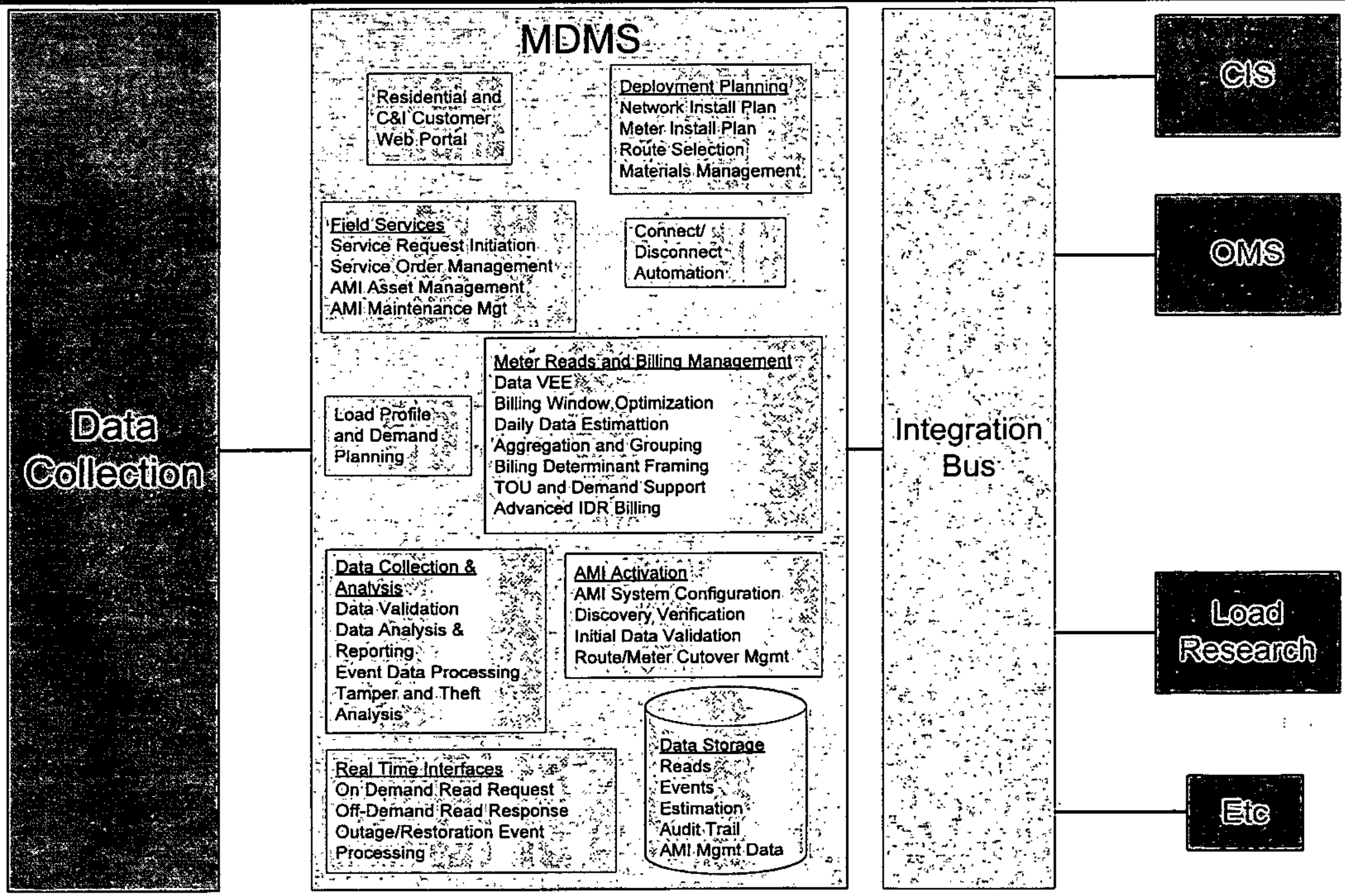
Advanced MDMS Functionality

- *Beyond core functions of the capture, processing and storing of meter reading data for the use by billing, MDMS can also involve:*
  - Customer data presentment support
  - Meter provisioning (add/modify/delete) of the AMI systems
  - Cutover process from manual to AMI meter reading & billing
  - AMI control (connect/disconnect, re-programming, schedule mgmt)
  - Data distribution beyond billing
  - Tampering detection and resolution
  - Outage and restoration data management
  - Data analysis and automated service order creation
  - Service Level Agreement/Key Performance Indicator tracking and reporting

What's Inside the Box?



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Trends in MDMS

- Major MDMS vendors can calculate billing determinants and perform VEE *(validation, estimation, and editing)*

- Utilities are looking more at the value-added functions
  - *Business Intelligence (revenue protection)*
  - *Customer Presentment (Web portals)*
  - *Demand Response Support*
  - *Outage Management Support*
  - *System Analysis Support (transformer load mgt)*

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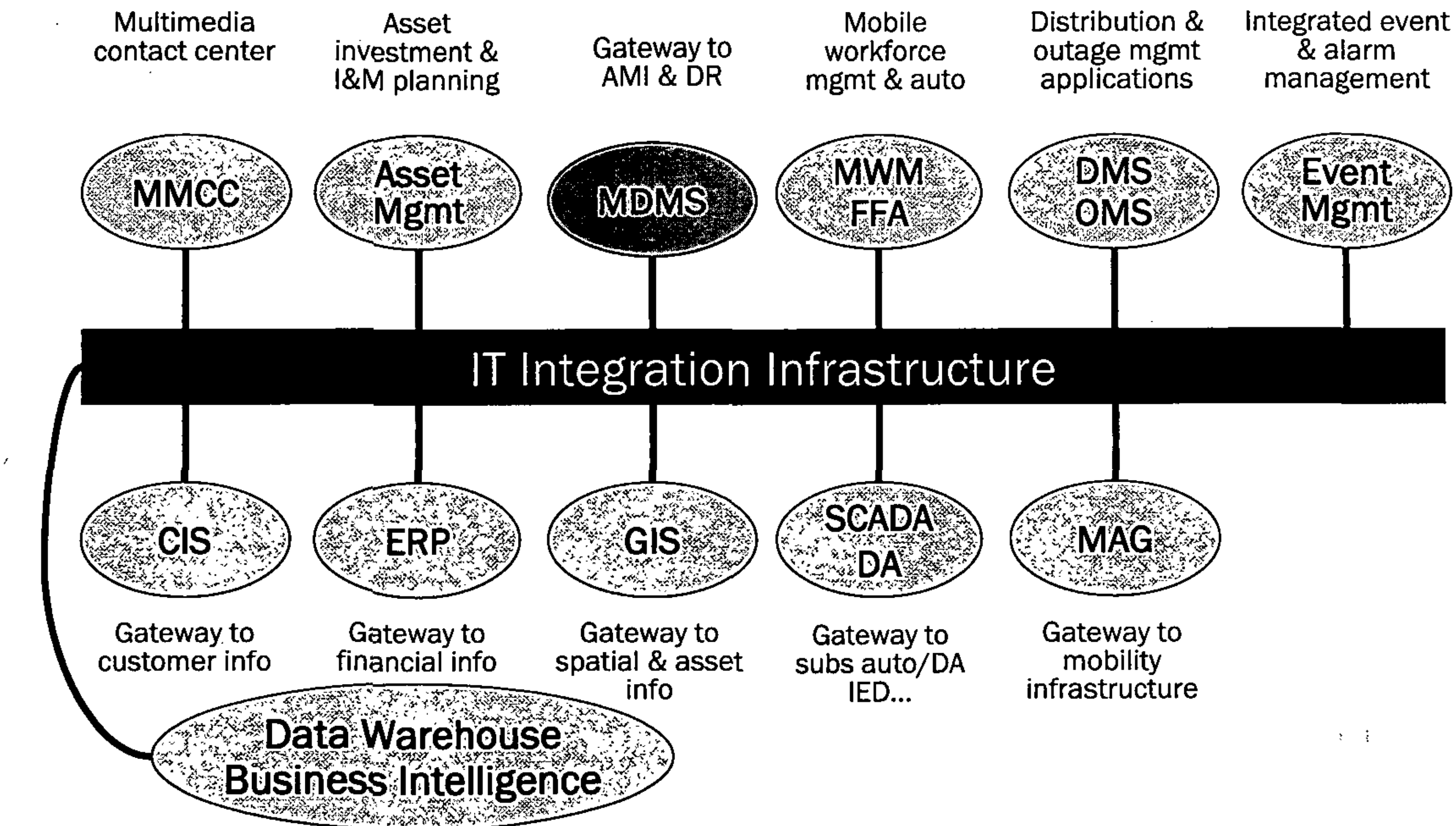
Commercial MDMS Vendors

- Aclara – EnergyVision®
- Ecologic Analytics (formally WACS) – Ecologic Analytics Meter Data Management System
- eMeter – EnergyIP™
- EnergyICT
- Itron – Itron Enterprise Edition Meter
- Oracle –Meter Data Management Solution (formally LODESTAR MDMS)

AMI & Enterprise Integration



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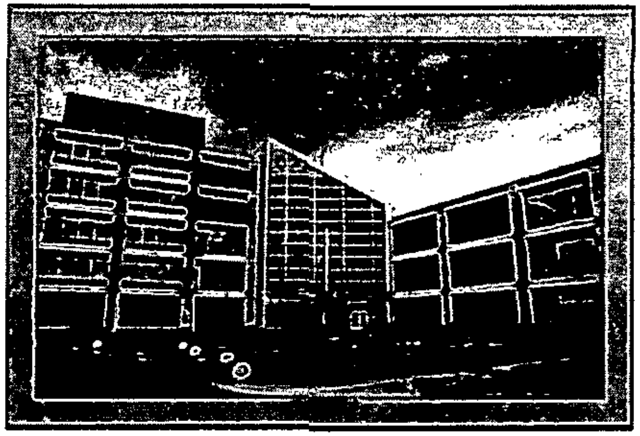
AMI Overview

Jim Ketchledge

Introduction to Enspiria Solutions



A leading provider of Consulting and Systems Integration services, providing in-depth Smart Grid technology expertise by defining and delivering strategies and solutions that benchmark the intelligent utilities of tomorrow.

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Fact and Figures:

- Incorporated: October 2003
- Employees average in excess of 20 years of industry experience
- Extensive background working with electric, gas and water utilities
- Acquired Convergent Group -July 2004

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...helping our clients achieve the maximum value from their people and technology investments

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Enspiria AMI/MDMS Engagements

AMI Clients	AMI	MDMS	Visioning/ Strategic Planning	Business Case/ Cost-benefit Analysis	Requirements, Design, and Specifications	Technology/ Vendor Assessment	Regulatory Support	Deployment Options/ Implementation Plan	RFP Development/ Evaluation and Selection	Systems Deployment and Integration	Program Management/ Oversight
Large Midwestern USA Utility	X	X	X	X	X	X	X	X	X	X	X
California Municipal Utility)		X	X		X	X		X	X		
Large Eastern USA Utility	X	X	X	X	X	X	X	X	X		
California Municipal Utility	X	X	X			X		X			
Medium size southern USA Utility	X			X							
Colorado Municipal Utility	X	X			X					X	
Medium size Midwestern Utility	X		X	X	X	X		X			
Large Southern USA utility	X	X	X	X	X	X		X	X		
Small Western Canada Utility	X		X	X	X	X		X			
Large Midwestern USA Utility	X	X	X	X	X	X		X	X		X
Large Midwestern USA Utility	X		X	X	X			X			
Medium size Western USA Utility	X	X	X	X	X	X	X	X	X		
Medium Size Municipal Utility	X		X		X	X		X	X		
Medium Size Municipal Utility	X	X	X	X	X			X		X	X
Medium Size Municipal Utility	X		X	X				X			
Large Eastern Canada Utility		X			X					X	
Large Western USA Utility	X			X							
Large Eastern USA Utility	X		X	X	X	X		X	X		
Medium Size Western USA Utility	X									X	X
Large Western USA Utility	X	X	X	X	X	X	X	X	X	X	X
Large Western USA Utility	X	X		X	X	X					
Small Florida Municipal Utility		X	X		X				X		
Medium Size Western USA Utility		X			X	X			X		
Large Southern USA Utility	X	X	X		X			X	X	X	

*Utilities That Enspiria Staff Supported Prior to Joining Enspiria

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Advanced Metering Infrastructure

"Advanced metering infrastructure," as defined by FERC is:

. . . a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.

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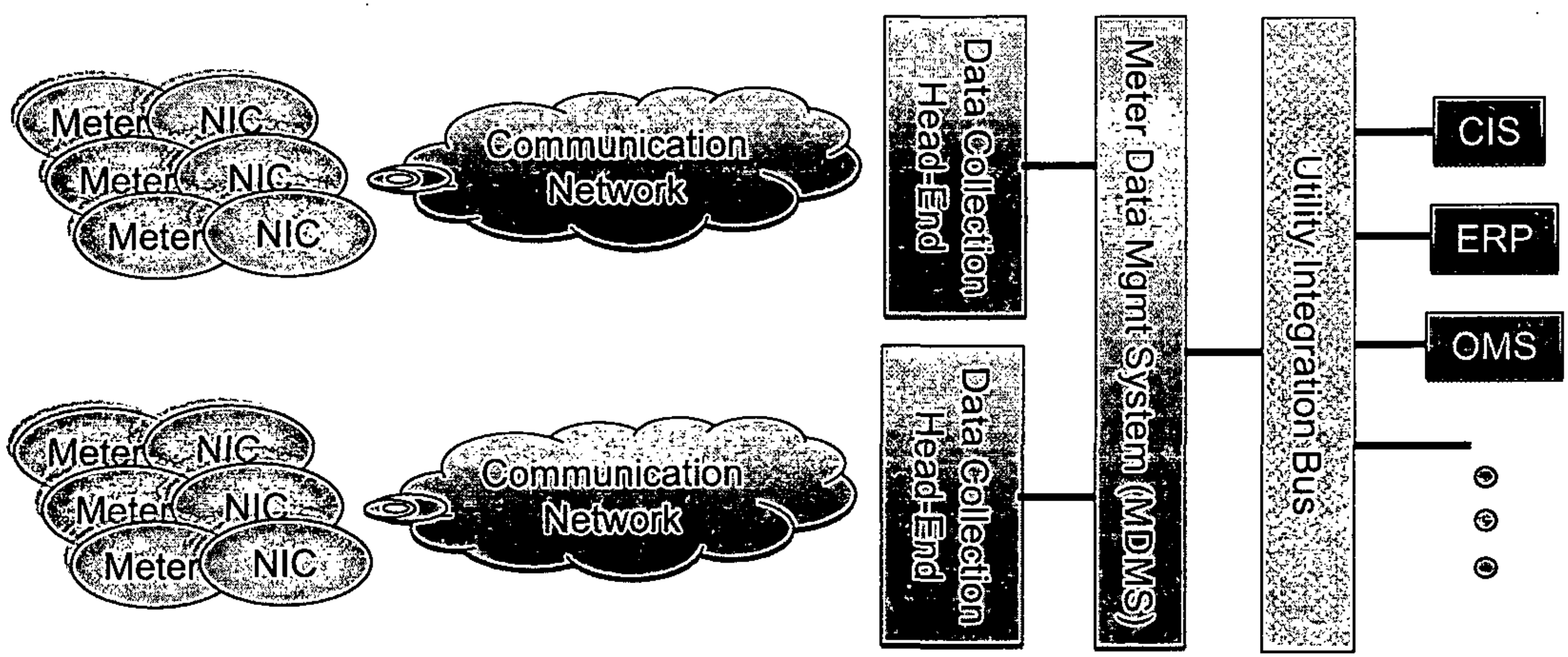
Advanced Metering Infrastructure

- Evolved from "Automated Meter Reading" or AMR
- AMI is a foundational system that adds
  - Capability to analyze the available data
  - Two-way communications to the meter
  - Support for presentment of interval data to customers
  - Support of advanced features such as demand response
  - Facilitated operational benefits such as distribution system optimization or enhanced outage management
  - Improved customer service
  - Quickly gather critical information that provides insight to company decision-makers.

The Three Major AMI Components

- AMI or "Smart" Meter
  - An electrical, gas, or water meter with a built in network interface card (communications module)
  - Supports different rate programs and interval data reads
- Communication Network
  - Enables two-way communications between the endpoints (meters, load control devices, etc.) and "Head End"
- Operating or "Head-End" Software
  - Manages vendor's AMI system network
  - Coordinates collection of meter information
  - Interfaces with a Meter Data Management System or other IT systems

AMI System + Interfaces



AMI Meter
Integrated Network Interface Card (NIC)

AMI Network
Communication & Data Collection

MDMS

Enterprise Integration

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AMI Benefits

- Improved **Customer Information** via provision of customer energy usage and related data via Internet and In-Home Displays
- Allows widespread application of **Time-Differentiated Rates**
- Increased **Customer Satisfaction**
- Improved **Asset Utilization**
- Increase **Distribution System** & **Service Reliability**
- Improve **Load Forecasting, System Planning** and **Engineering** through enhanced customer data
- Improved **Meter Accuracy** and **Theft Detection**
- Facilitate increased **Renewable and dispersed generation**
- **Enable Smart Grid applications**

AMI Market Overview

Marked increase in AMI functionality in last 12 months

- Service disconnect “under glass”
- Remotely downloadable firmware
- HAN connectivity

New Federal Legislation focused on Smart Grid

- ARRA funding details in development for ~$4.5B in matching funds

AMI is an enabler for demand response program

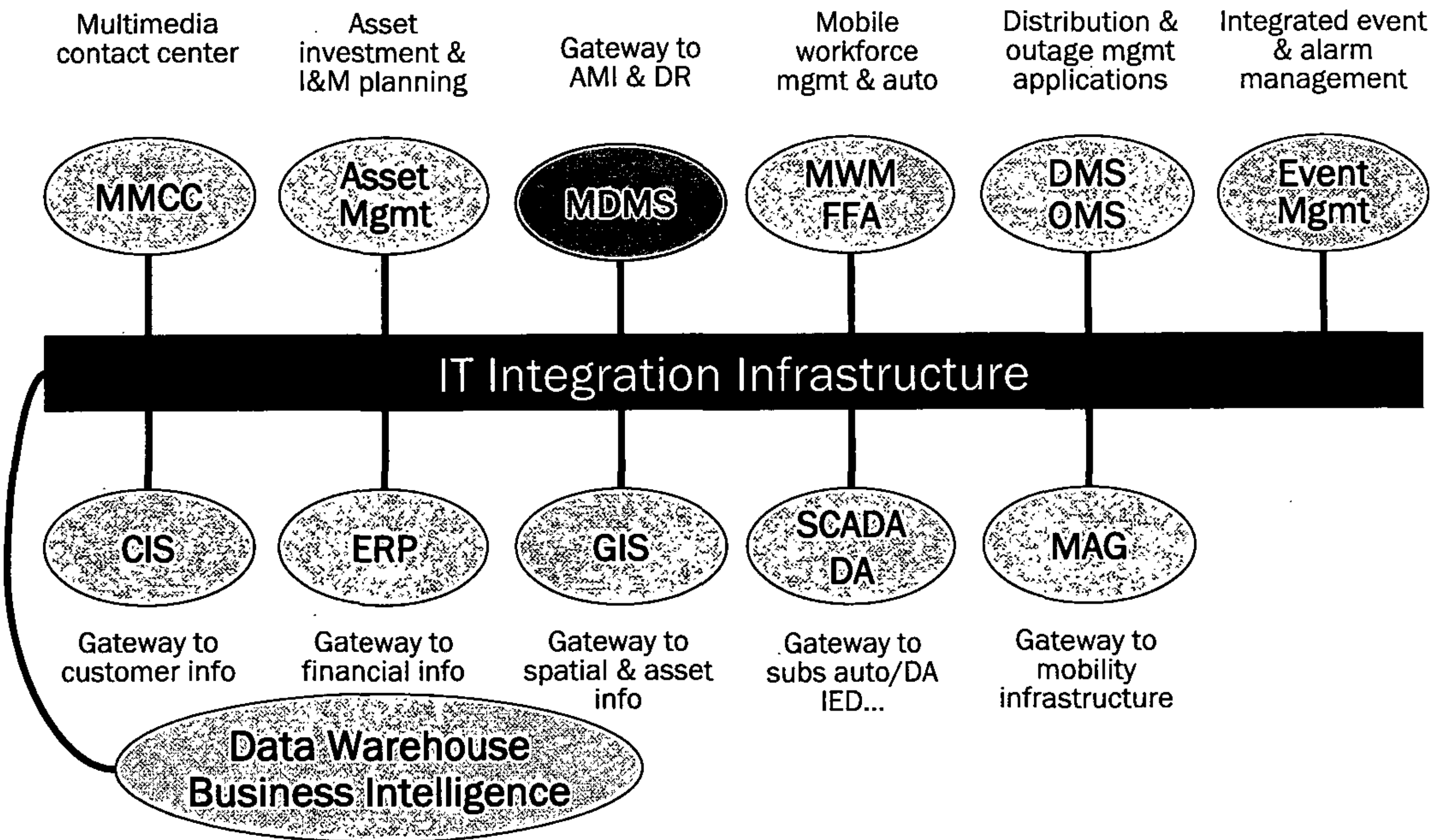
- Provides a means to capture time-based consumption data
- Serves as a communications platform for DR control signals

AMI more prevalent in states facing

- Higher overall rates
- Aging infrastructure
- Renewable resources or conservation emphasis

AMI is a fundamental building block for the Smart Grid

AMI & Enterprise Integration



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Ref: Exhibit 9.

On Exhibit 9, there appears to be certain items that include captions indicating that a certain phase has been removed. For example, there is a rectangle that has the caption "C&I presentment (MV Web) Removed Phase 3." Please explain what the removal of these items mean.

HECO Companies' Response:

The rectangle that has the caption "C&I presentment (MV Web) Removed Phase 3" indicates that the customer presentment capability of the Meter Data Management System will replace the functionality of the MV Web capability of the MV-90 system.

CA-IR-30

Ref: Application.

In the HCEI Agreement, the Companies are supposed to "minimize the financial impacts on low income and disadvantaged customers who have limited options through a combination of tiered rates and lifeline rates."

a. Please indicate the appropriate citations to the application and supporting exhibits where HECO has outlined its plan to minimize the financial impacts on low income and disadvantaged customers.
b. If not already discussed, please identify the criteria that HECO will use to determine which customers will be able to qualify as low income or disadvantaged in order to have the impact of the AMI project minimized on electricity bills.

HECO Companies' Response:

a. The instant application does not address how the Companies plan to minimize financial impacts on low income and disadvantaged customers. These issues are being addressed in Docket No. 2009-0096, Application for Lifeline Rate Program, where the Companies have proposed a monthly bill credit for eligible customers. The AMI surcharge would be a component of the total electric bill to which a Lifeline Rate bill credit would be applied. See Docket No. 2009-0096, Application for Lifeline Rate Program, for further details regarding the proposed eligibility requirements and bill credit amounts by island.
b. Not applicable. See response to part a above.

CA-IR-31

Ref: Vendors.

Whether for services, hardware, software, or any combination, please provide the following for each of the vendors that HECO intends to rely upon for this project:

a. Years of operation;
b. audited financial statements; and
c. Copies of the most recent SEC form 8-Ks.

<u>HECO Companies' Response:</u>

Note: Sensus Metering Systems Inc. is the only vendor that has been selected at this time. All answers below pertain to Sensus Metering Systems Inc.

a. The Company was formed on December 18, 2003 through the acquisition of the metering systems and certain other businesses of Invensys PLC ("Invensys"). Prior to the acquisition, the Company had no active business operations.

b. Audited financial data from the vendor's consolidated financial statements is provided with this Attachment 1, SEC Form 10-K, Part II, Item 6.

c. The vendor's most recent SEC Form 8-K is provided as Attachment 2 to this response.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT
PURSUANT TO SECTIONS 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED MARCH 31, 2009**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 333-113658

Sensus Metering Systems (Bermuda 2) Ltd.	Sensus Metering Systems Inc.
(Exact name of registrant as specified in its charter)	(Exact name of registrant as specified in its charter)

Bermuda	98-0413362	Delaware	51-0338883
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8537 Six Forks Road, Suite 400, Raleigh, North Carolina 27615
(Address of principal executive offices) (Zip Code)

(919) 845-4000
(Registrants' telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K, or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of May 14, 2009, Sensus Metering Systems (Bermuda 2) Ltd. had 12,000 common shares outstanding, all of which were owned by Sensus Metering Systems (Bermuda 1) Ltd., and Sensus Metering Systems Inc. had 283.603994 shares of common stock outstanding, all of which were owned by Sensus Metering Systems (Bermuda 2) Ltd.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a) None.

(b) Not applicable.

(c) None.

ITEM 6. SELECTED FINANCIAL DATA

We have derived the following selected consolidated financial data from our audited consolidated financial statements. The information set forth below is not necessarily indicative of the results of future operations and should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes included elsewhere in this Annual Report.

(in millions)	Year Ended March 31, 2005	Year Ended March 31, 2006	Year Ended March 31, 2007	Year Ended March 31, 2008	Year Ended March 31, 2009
Income Statement Data:					
Net sales	$569.8	$613.9	$632.9	$ 694.2	$ 670.7
Loss from continuing operations	(4.2)	(3.2)	(8.1)	(10.1)	(49.9)
Other Financial Data:					
Restructuring costs (1)	$ 8.1	$ 7.2	$ 8.5	$ 7.0	$ 9.9
Deferred revenue less deferred costs primarily from long-term AMI electric and gas contracts	—	—	—	5.1	62.4
Capital expenditures (including intangibles and software development costs)	22.4	24.8	18.3	27.8	36.7
Balance Sheet Data:					
Cash and cash equivalents	$ 54.9	$ 52.6	$ 34.9	$ 37.6	$ 37.9
Total deferred costs	—	—	—	26.4	99.3
Total assets	940.2	935.1	973.2	1,019.3	1,112.3
Total debt	500.4	485.6	475.5	454.5	438.9
Total deferred revenue	—	—	—	37.8	168.8
Stockholder's equity	194.0	186.4	226.5	216.8	166.3

(1) For additional information regarding restructuring costs, see Note 7 under "Notes to Consolidated Financial Statements" in Item 8 of this Annual Report. Restructuring costs are added to net income for purposes of determining compliance by the Company with the financial covenants of both the senior credit facilities and the indentures governing the notes.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Annual Report on Form 10-K includes certain statements that may be deemed to be "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. When used in this report, the words "anticipate," "believe," "estimate," "expect," "intend," "plan" and similar expressions as they relate to us are intended to identify these forward-looking statements. All statements by us regarding our expected financial position, sales, cash flow and other operating results, business strategy, financing plans,

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of Earliest Event Reported): May 15, 2009

Commission file number 333-113658

Sensus Metering Systems (Bermuda 2) Ltd.	Sensus Metering Systems Inc.
(Exact name of registrant as specified in its charter)	(Exact name of registrant as specified in its charter)

Bermuda	98-0413362	Delaware	51-0338883
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8537 Six Forks Road, Suite 400, Raleigh, North Carolina 27615
(Address of principal executive offices) (Zip Code)

(919) 845-4000
(Registrants' telephone number, including area code)

Not applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02 Results of Operations and Financial Condition

On May 15, 2009, Sensus Metering Systems (Bermuda 2) Ltd. (the "Company") issued a press release setting forth certain financial results of the Company for the fiscal quarter ended March 31, 2009. A copy of the press release is furnished as Exhibit 99.1 hereto.

In accordance with General Instruction B.2 of Form 8-K, the information contained in this report and in the accompanying exhibit is being furnished to the Securities and Exchange Commission and shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that section, nor shall such information be incorporated or deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits. The following exhibit is being furnished herewith:

99.1 Press release dated May 15, 2009.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

SENSUS METERING SYSTEMS (BERMUDA 2) LTD.

Dated: May 15, 2009

By: /s/ Peter Mainz
Name: Peter Mainz
Title: Chief Executive Officer & President

SENSUS METERING SYSTEMS INC.

Dated: May 15, 2009

By: /s/ Peter Mainz
Name: Peter Mainz
Title: Chief Executive Officer & President

Exhibit 99.1

Press Release

sensus
The Measure of the Future

Sensus Announces Fiscal Fourth Quarter 2009
Financial Results and Earnings Call

Record Adjusted Net Sales[1]

Raleigh, NC (May 15, 2009) – Sensus, a leading provider of high-value advanced metering infrastructure ("AMI") and metering system solutions to utilities worldwide, today announced financial results for the fiscal fourth quarter ended March 31, 2009. Total fiscal fourth quarter net sales declined from $184.8 million, reported in the prior year, to $169.0 million due primarily to reduced demands for our gas and water meters resulting from historic low building starts in the residential and commercial real estate markets in North America coupled with reduced demands for our precision die cast products due to a weak U.S. automotive market. Offsetting these contracting demands was growth in water and heat meters sales outside of North America coupled with AMI system and products in North America. Net loss was $18.7 million, and included $14.4 million of goodwill impairment, compared to a net loss of $0.6 million in the prior period. Adjusted Net Sales[1] improved to $216.2 million from $204.8 million representing a 6% improvement over the same quarter in the prior year. The Company recorded Adjusted EBITDA[1] of $36.0 million compared to $31.4 million in the prior year, representing a 15% improvement in the profitability measure.

Sensus continues to focus on delivering advanced technology and communications systems to our customers. Our ongoing effort to build the "Smart Grid" continues to accelerate, as evidenced by more than 2.8 million SmartPoints we have deployed, and are operational, demonstrating FlexNet® technology and functionality in utility billing and monitoring in systems at consistently high accuracy levels. We continue to drive customer confidence in our system through added functionality, improved efficiencies and increased scale. We have also expanded our offerings to leverage our network system's reach to include demand response and distribution automation, in addition to smart metering technology.

"Our strong fourth quarter and annual financial performance was achieved in a very difficult global environment. Annual records were set for both Adjusted Net Sales[1] of $806.1 million, an 11% improvement over prior year, and Adjusted EBITDA[1] of $112.2 million, an improvement of more than 20%. During the year, we took several actions to improve our focus on scalability, flexibility, and customer satisfaction. While navigating this challenging environment, we continued to invest where necessary to deliver on our commitments, to expand our product offerings and to support our customers' needs. I am pleased with the results for the year. We will continue to build on our momentum and to extend and leverage our efforts as we enter a new fiscal year. Our primary focus will continue to be on strengthening our position and delivering performance and value to our customers," said Peter Mainz, Chief Executive Officer and President of Sensus.

Key Highlights for the Fiscal Fourth Quarter

- 15% improvement in Adjusted EBITDA[1] to $36.0 million.
- 6% increase in Adjusted Net Sales[1] and a record level of $216.2 million.
- 18% improvement in GAAP operating cash flow.
- Adjusted Net Sales[1] book-to-bill[2] of over 1 to 1.
- $467 million potential future revenue and 5.7 million endpoints from AMI contracts.
- In excess of a quarter million new endpoints contracted during the quarter.
- $37.9 million of cash-on-hand at March 31, 2009.

(more)

Fiscal Fourth Quarter Earnings Conference Call

The Company's Form 10-K for the year ended March 31, 2009, which includes financial statements and related notes together with management's discussion and analysis of such results, is now available.

A conference call with analysts to discuss these results will be held on May 19, 2009 at 11:00 AM (EDT). To access the conference call, please dial 800-688-0796 (domestic access) or 617-614-4070 (international access) and reference Passcode: 14794286. It is recommended that you dial in five to ten minutes prior to the call to allow time for processing participant information. A replay of the call will be available until May 26, 2009 by dialing 888-286-8010 (domestic access) or 617-801-6888 (international access) and referencing Passcode: 11168184.

Investor Contacts:
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James J. Hilty
Vice President, Business Development
(919) 845-4007
jim.hilty@sensus.com

About Sensus

Sensus is a time-tested technology and communications company providing data collection and metering solutions for water, gas and electric utilities around the world. Sensus is a transforming force for the utilities of tomorrow through its ability to help customers optimize resources, as well as to meet conservation and customer service objectives. Sensus customers rely on the Company for expert, reliable service in order to meet challenges and exceed goals. For more information, visit www.sensus.com.

All statements in this release, other than historical facts, are made in reliance on the safe-harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements involve risks and uncertainties and are subject to change at any time. These statements reflect the Company's current expectations regarding its financial position, revenues, cash flow and other operating results, business strategy, financing plans, forecasted trends related to the markets in which the Company operates, legal proceedings and similar matters. The Company's expectations expressed or implied in these forward-looking statements may turn out to be incorrect. The Company's actual results could be materially different from its expectations because of various risks. These risks, some of which are discussed under the caption "Risk Factors" in the Company's Annual Report on Form 10-K (SEC File No. 333-113658) for the fiscal year ended March 31, 2009 as filed with the Securities and Exchange Commission on May 15, 2009, include the Company's susceptibility to macroeconomic downturns in the United States and abroad, conditions in the residential, commercial and industrial construction markets and in the automotive industry, the Company's dependence on new product development and intellectual property, and the Company's dependence on independent distributors and third-party contract manufacturers, automotive vehicle production levels and schedules, the Company's substantial financial leverage, debt service and other cash requirements, liquidity constraints and risks related to future growth and expansion. Other important risks that could cause actual events or results to differ from those contained or implied in the forward-looking statements include, without limitation, the Company's ability to integrate acquired companies, general economic and business conditions, competition, adverse changes in the regulatory or legislative environment in which the Company operates, customer cancellations and other factors beyond the Company's control.

(more)

(1) Non-GAAP Measures

During the fourth quarter of fiscal 2009, Sensus Metering Systems continued the deployment of its new, advanced FlexNet® AMI solutions under contracts executed with several North American electric and gas utilities. These contracts, which extend up to 20 years and cover 7.9 million electric and gas endpoints, contain significant hardware and software components as well as ongoing customer support. Due to the significant advanced technology and software and the absence of stand-alone customer support sales prices, customer billings and incremental direct costs related to these contracts are required to be deferred in accordance with U.S. GAAP for income statement recognition purposes and amortized ratably over the life of the contracts. This deferral has no impact on cash flow since billings to customers occur as the network infrastructure and related endpoints are deployed and the associated costs are incurred, generally over the first several years of the contract term. To enhance the comparability and usefulness of its financial information, the Company provides certain non-GAAP measures to describe more fully the results of its underlying business. Specifically, the Company utilizes the measures of Adjusted Net Sales and Adjusted EBITDA, which are defined as follows:

- Adjusted Net Sales is defined as net sales as determined under U.S. GAAP adjusted to add back customer billings (net of amortization) related to multi-element contracts that have been deferred under the provisions of SOP 97-2.
- Adjusted EBITDA is defined as earnings before interest expense, depreciation and amortization, minority interest and income taxes plus (a) customer billings less the associated incremental direct costs (both net of amortization) related to multi-element contracts that have been deferred under SOP 97-2, (b) restructuring costs and (c) management fees, and adjusted for other nonrecurring items.

Information regarding Adjusted Net Sales and Adjusted EBITDA is provided because management considers these measures important in evaluating and understanding the Company's operating and financial performance. Management believes these measures provide useful information for investors in trending, analyzing and benchmarking the performance and value of the business. Internally these measures are used in our incentive compensation plans. Management believes that these non-GAAP financial measures provide meaningful supplemental information regarding our performance by adjusting for certain items that may not be indicative of our recurring core operating results. Management also believes that Adjusted Net Sales and Adjusted EBITDA provide important performance measures to our management and investors because they reflect customer billings (net of related incremental costs, in the case of Adjusted EBITDA) which we are required to defer under SOP 97-2. These measures help our management and investors to better quantify the growth of our AMI technology solutions business. However, these metrics for measuring the Company's financial results may be different from comparable information provided by other companies and should not be used as an alternative to the Company's operating and other financial information as determined under U.S. GAAP.

(more)

A reconciliation of each of these non-GAAP measures to its most closely related U.S. GAAP measure is set out in the table below (in millions):

	Fiscal Quarter Ended March 31, 2009	Fiscal Quarter Ended March 31, 2008	Fiscal Year Ended March 31, 2009	Fiscal Year Ended March 31, 2008
Net sales	$ 169.0	$ 184.8	$ 670.7	$ 694.2
Revenue from contracts deferred under SOP 97-2 (net of amortization)	47.2	20.0	135.4	31.4
Adjusted Net Sales	$ 216.2	$ 204.8	$ 806.1	$ 725.6

	Fiscal Quarter Ended March 31, 2009	Fiscal Quarter Ended March 31, 2008	Fiscal Year Ended March 31, 2009	Fiscal Year Ended March 31, 2008
Net loss	$ (18.7)	$ (0.6)	$ (49.9)	$ (10.1)
Depreciation and amortization	11.4	12.1	46.6	47.7
Interest expense, net	9.6	10.4	39.9	41.8
Income tax (benefit) provision	(7.4)	0.8	(19.9)	(2.6)
Minority interest	0.6	0.5	2.4	1.9
Revenue less incremental direct costs from contracts deferred under SOP 97-2 (net of amortization)	23.5	3.1	62.4	5.1
Restructuring costs	1.7	4.5	9.9	7.0
Management fees	0.9	0.6	3.1	2.6
Goodwill impairment	14.4	—	14.4	—
Other nonrecurring items (a)	—	—	3.3	—
Adjusted EBITDA	$ 36.0	$ 31.4	$ 112.2	$ 93.4

(a) Represents a nonrecurring, non-cash charge for residual manufacturing overhead costs related to the outsourcing of certain manufacturing activities.

(2) Book-to-bill

Book-to-bill is calculated as orders received during the quarter divided by Adjusted Net Sales.

(more)

FISCAL 2009 FOURTH QUARTER UNAUDITED FINANCIAL STATEMENTS

SENSUS METERING SYSTEMS (BERMUDA 2) LTD.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Fiscal Quarter Ended March 31, 2009	Fiscal Quarter Ended March 31, 2008
NET SALES	$ 169.0	$ 184.8
COST OF SALES	129.9	132.1
GROSS PROFIT	39.1	52.7
OPERATING EXPENSES:		
Selling, general and administrative expenses	35.3	31.7
Restructuring costs	1.7	4.5
Amortization of intangible assets	2.9	3.5
Impairment of goodwill	14.4	—
Other operating expense, net	0.5	0.8
OPERATING (LOSS) INCOME	(15.7)	12.2
NON-OPERATING EXPENSE:		
Interest expense, net	(9.6)	(10.4)
Other expense, net	(0.2)	(1.1)
(LOSS) INCOME BEFORE INCOME TAXES AND MINORITY INTEREST	(25.5)	0.7
(BENEFIT) PROVISION FOR INCOME TAXES	(7.4)	0.8
LOSS BEFORE MINORITY INTEREST	(18.1)	(0.1)
MINORITY INTEREST	(0.6)	(0.5)
NET LOSS	$ (18.7)	$ (0.6)

(more)

SENSUS METERING SYSTEMS (BERMUDA 2) LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Fiscal Quarter Ended March 31, 2009	Fiscal Quarter Ended March 31, 2008
OPERATING ACTIVITIES:		
Net loss	$ (18.7)	$ (0.6)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation	7.3	8.2
Amortization of intangible assets	2.9	3.5
Amortization of software development costs	1.2	0.4
Amortization of deferred financing costs	0.7	0.7
Deferred income taxes	(27.1)	(5.9)
Net loss (gain) on sale of assets	0.1	(0.1)
Non-cash restructuring charges	0.2	0.2
Net loss on foreign currency transactions	0.6	1.2
Minority interest	0.6	0.5
Impairment of goodwill	14.4	—
Changes in assets and liabilities used in operations, net of effects of acquisition:		
Accounts receivable	(10.3)	(16.4)
Inventories	7.9	6.7
Other current assets	(3.1)	(0.4)
Accounts payable, accruals and other current liabilities	24.1	27.9
Income taxes payable	18.2	7.2
Deferred revenue less deferred costs primarily from long-term AMI electric and gas contracts	23.5	3.1
Other	(3.8)	—
Net cash provided by operating activities	38.7	36.2
INVESTING ACTIVITIES:		
Expenditures for property, plant and equipment	(9.4)	(7.8)
Purchases of intangible assets	(0.8)	—
Software development costs	(3.0)	(0.9)
Global Meter acquisition	(1.3)	—
Net cash used in investing activities	(14.5)	(8.7)
FINANCING ACTIVITIES:		
Decrease in short-term borrowings	(10.3)	(13.9)
Principal payments on debt	(3.0)	(10.0)
Net cash used in financing activities	(13.3)	(23.9)
Effect of exchange rate changes on cash	(0.6)	0.8
INCREASE IN CASH AND CASH EQUIVALENTS	10.3	4.4
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	$ 27.6	$ 33.2
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 37.9	$ 37.6
SUPPLEMENTAL DISCLOSURES OF CASH FLOW:		
Cash paid during the period for:		
Interest, net	$ 3.7	$ 3.5
Income taxes, net of refunds	$ 1.0	$ 0.2

(more)

FISCAL 2009 AUDITED FINANCIAL STATEMENTS

SENSUS METERING SYSTEMS (BERMUDA 2) LTD.
CONSOLIDATED BALANCE SHEETS
(in millions, except per share and share data)

	March 31, 2009	March 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 37.9	$ 37.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1.2 and $1.5 at March 31, 2009 and 2008, respectively	112.8	107.1
Other	2.9	1.0
Inventories, net	66.4	72.3
Prepayments and other current assets	11.8	12.8
Deferred income taxes	6.5	5.0
Deferred costs	10.6	3.1
Total current assets	248.9	238.9
Property, plant and equipment, net	131.5	138.4
Intangible assets, net	187.3	199.2
Goodwill	394.5	377.6
Deferred income taxes	39.5	17.4
Deferred costs	88.7	23.3
Other long-term assets	21.9	24.5
Total assets	$1,112.3	$1,019.3
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 87.1	$ 81.3
Accruals and other current liabilities	80.7	67.8
Current portion of long-term debt	38.5	0.1
Short-term borrowings	4.9	5.8
Income taxes payable	2.9	—
Restructuring accruals	7.3	5.2
Deferred revenue	19.0	5.4
Total current liabilities	240.4	165.6
Long-term debt, less current portion	395.5	448.6
Pensions	44.4	52.5
Deferred income taxes	76.4	71.9
Deferred revenue	149.8	32.4
Other long-term liabilities	27.6	21.3
Minority interest	11.9	10.2
Total liabilities	946.0	802.5
Commitments and Contingencies (Note 18)		
STOCKHOLDER'S EQUITY:		
Common stock, par value $1.00 per share, 12,000 shares authorized, issued and outstanding	—	—
Paid-in capital	245.4	243.2
Accumulated deficit	(79.3)	(29.3)
Accumulated other comprehensive income	0.2	2.9
Total stockholder's equity	166.3	216.8
Total liabilities and stockholder's equity	$1,112.3	$1,019.3

(more)

SENSUS METERING SYSTEMS (BERMUDA 2) LTD.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended March 31, 2009	Year Ended March 31, 2008	Year Ended March 31, 2007
NET SALES	$ 670.7	$ 694.2	$ 632.9
COST OF SALES	523.4	510.3	453.8
GROSS PROFIT	147.3	183.9	179.1
OPERATING EXPENSES:			
Selling, general and administrative expenses	134.0	121.5	110.4
Restructuring costs	9.9	7.0	8.5
Amortization of intangible assets	13.5	19.7	23.6
Impairment of goodwill	14.4	—	—
Other operating expense, net	2.7	2.3	2.7
OPERATING (LOSS) INCOME	(27.2)	33.4	33.9
NON-OPERATING (EXPENSE) INCOME:			
Interest expense, net	(39.9)	(41.8)	(42.4)
Other (expense) income, net	(0.3)	(2.4)	1.9
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES AND MINORITY INTEREST	(67.4)	(10.8)	(6.6)
(BENEFIT) PROVISION FOR INCOME TAXES	(19.9)	(2.6)	1.0
LOSS FROM CONTINUING OPERATIONS BEFORE MINORITY INTEREST	(47.5)	(8.2)	(7.6)
MINORITY INTEREST	(2.4)	(1.9)	(0.5)
LOSS FROM CONTINUING OPERATIONS	(49.9)	(10.1)	(8.1)
GAIN FROM DISCONTINUED OPERATIONS	—	—	0.1
NET LOSS	$ (49.9)	$ (10.1)	$ (8.0)

(more)

SENSUS METERING SYSTEMS (BERMUDA 2) LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended March 31, 2009	Year Ended March 31, 2008	Year Ended March 31, 2007
OPERATING ACTIVITIES:			
Net loss	$ (49.9)	$ (10.1)	$ (8.0)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation	26.4	27.1	24.5
Amortization of intangible assets	13.5	19.7	23.6
Amortization of software development costs	6.7	0.9	—
Amortization of deferred financing costs	3.1	2.8	2.5
Deferred income taxes	(27.1)	(5.9)	(4.2)
Net gain on sale of assets	(0.1)	—	(1.6)
Non-cash restructuring charges	0.2	0.2	1.3
Net loss (gain) on foreign currency transactions	1.0	1.3	(1.7)
Minority interest	2.4	1.9	0.5
Impairment of goodwill	14.4	—	—
Changes in assets and liabilities used in operations, net of effects of acquisitions and divestitures:			
Accounts receivable	(13.0)	(2.4)	(3.7)
Inventories	2.0	(5.3)	(5.4)
Other current assets	(1.0)	1.7	(0.6)
Accounts payable, accruals and other current liabilities	19.8	14.3	(0.2)
Income taxes payable	3.0	—	(0.8)
Deferred revenue less deferred costs primarily from long-term AMI electric and gas contracts	62.4	5.1	—
Other	(3.1)	—	2.8
Net cash provided by operating activities	60.7	51.3	29.0
INVESTING ACTIVITIES:			
Expenditures for property, plant and equipment	(26.7)	(22.8)	(17.3)
Purchases of intangible assets	(1.2)	(0.3)	(0.4)
Software development costs	(8.8)	(4.7)	(0.6)
AMDS acquisition and subsequent contingent payments	(4.6)	(0.9)	(49.7)
Global Meter acquisition	(1.3)	—	—
Rongtai acquisition	—	—	(0.6)
DuPenn acquisition	—	—	(0.5)
Proceeds from sale of assets	0.2	—	1.8
Net cash used in investing activities	(42.4)	(28.7)	(67.3)
FINANCING ACTIVITIES:			
(Decrease) increase in short-term borrowings	(1.0)	1.3	(0.1)
Principal payments on debt	(14.7)	(23.0)	(10.0)
Debt issuance costs	—	—	(0.6)
Equity contributions from Bermuda 1 for AMDS acquisition	—	—	30.4
Net cash (used in) provided by financing activities	(15.7)	(21.7)	19.7
Effect of exchange rate changes on cash	(2.3)	1.8	0.9
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	0.3	2.7	(17.7)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	$ 37.6	$ 34.9	$ 52.6
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 37.9	$ 37.6	$ 34.9
SUPPLEMENTAL DISCLOSURES OF CASH FLOW:			
Cash paid during the period for:			
Interest, net	$ 36.2	$ 38.9	$ 40.6
Income taxes, net of refunds	$ 3.6	$ 4.0	$ 6.2

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CA-IR-32

Ref: Vendors.

For each of the vendors that have been identified, please provide the following:

a. A list of the three most recent projects that have been completed;
b. The budgeted or bid cost for each project;
c. The actual cost for each project;
d. The original scope of each project and changes, if any, to the scope of the project; and
e. Copies of any customer comments on the vendor.

HECO Companies' Response:

a. A listing of Sensus Metering Systems' ("Sensus") recently completed (electric) AMI projects is provided as Attachment 1 to this response. The projects listed in Attachment 1 are smaller than Sensus' current projects with the Southern Company, Alliant Energy, and Portland General Electric. None of these larger projects have been completed.

b. The budgeted or bid cost for each project is not available.

c. The actual cost of each project is not available.

d. The original scope of projects is only known from the approximate number of meters as shown below. Scope changes are not known since this is proprietary information that Sensus and their customers have not released. However, the approximate numbers of meters to be installed are shown below.

Southern Company ("Southern"):

Meters Contracted:	4.3 million
Status:	1.1 million meters installed

Alliant Energy ("Alliant"):

Meters Contracted:	1 million
Status:	0.21 million meters installed

Portland General Electric ("PGE"):

Meters Contracted: 0.84 million

Status: .04 million meters installed

e. As stated in the Companies response to CA-IR-17, the Companies participate in the Sensus FlexNet Users Group ("SFUG"), in which utilities are able to bring up issues, concerns, and development requests and solutions to problems encountered. However, the SFUG charter restricts the dissemination of information to SFUG members only. Some Sensus customers and Sensus itself issue press releases as their AMI projects move forward. Attachment 2 to this response provides an update to PGE's AMI project and Attachment 3 to this response provides a Southern press release documenting the installation of their millionth smart meter.

Region	Utility	City	State	RNI Planned	RNI Installed	RNI % Installed	TGB Planned	TGB Installed	TGB % Installed	Elec Planned	Elec Installed	Elec % Installed
Canada	NewMarket	Newmarket	CANADA	1	1	100%	2	2	100%	22,500	25,746	114%
East	Amory	Amory	MS	1	1	100%	1	1	100%	1,300	1,300	100%
East	East Grand Forks	East Grand Forks	MN	1	1	100%	1	1	100%	3,370	3,370	100%
West	Nephi/Levan/Mona	Nephi/Levan/Mona	UT	1	1	100%	1	1	100%	2,300	2,300	100%
Mid West	Oconomowoc	Oconomowoc	WI	1	1	100%	1	1	100%	9,000	9,000	100%
Canada	Powerstream (phase I)	Markham, Richmond Hill	CANADA	1	1	100%	4	7	175%	80,000	80,000	100%
East	Baltimore Gas & Elec - Pilot ©	Baltimore	MD	1	1	100%	5	5	100%	1,635	1,635	100%
East	Town of Skaneateles ©	Skaneateles	NY	1	1	100%	1	1	100%	300	299	100%
Mid West	Ponca City	Ponca City	OK	1	1	100%	5	5	100%	16,000	15,900	99%
Canada	TAY	Victoria Harbor	CANADA	1	1	100%	1	1	100%	4,000	3,925	98%

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News Room

April 15, 2009

PGE moves forward on smart meter installation territory-wide
Successfully completes system testing installing thousands of meters

PORTLAND, Ore. — Portland General Electric Company (PGE) (NYSE:POR) will begin rolling out more than 800,000 "smart meters" across its 4,000-square-mile service area this week after successfully completing its smart metering systems testing program.

The next-generation electrical meters, which will be read remotely by PGE, will help the utility and its customers manage energy use, as well as enhance customer service and reduce operating expenses.

PGE began installing smart meters last year in selected test neighborhoods — urban and rural — before rolling them out territory-wide. The rest of the smart meters will be installed in an 18-month process slated for completion by late 2010.

"Systems testing went well and we are moving forward to complete the installation of smart meters for all of our customers," said Jim Piro, president and CEO of PGE. "Smart meters will allow us to offer our customers better service and reduce our operating costs. Smart meters are also the foundation for future 'smart grid' and 'smart home' technology necessary to meet our customers' future energy needs."

The new meters, which communicate over a wireless network much like a cell phone system, will provide PGE with two-way communications to its residential and commercial meters, enabling many customer benefits:

- **Cost savings:** PGEanticipates millions in operational cost savings per year once the system is fully up and running, saving customers at least $34 million (net present value) over the next 20 years.

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· **Environmental benefits:** Fewer meter-reading vehicles will eliminate 1.2 million miles of driving, save 80,000 gallons of gasoline and reduce CO_2 emissions by 1.5 million pounds every year.

· **Helps customers save energy:** Within the next year, customers with smart meters will be able to access detailed information online or via customer service about their power consumption, allowing them to see how their activities affect power usage and develop strategies to use energy wisely. Customers will also have the ability to pick a preferred bill due date.

· **Speeds power restoration:** In the future, PGE will be able to respond to power outages faster through information received via the smart metering system. The new meters will be able to tell PGE if a customer is experiencing a power outage, helping PGE dispatch repair crews more efficiently and restore service faster.

· **Future demand response programs:** The new system is also expected to support the future development of such programs as demand response — a pricing structure program that encourages customers to use energy at less expensive times of the day, when the peak demand is lower; and direct load control programs — a program in which customers would agree to permit the utility to turn off certain appliances for limited periods when demand is high. These types of programs will reduce the need for new generation resources to meet peak demand.

The capital cost of the project is expected to be $130-135 million. The smart metering system, also known as advanced metering infrastructure (AMI), was purchased from Sensus Metering. Residential and smaller business customer meters will be installed by Wellington Energy, PGE's contract meter installer. PGE's meter services will install meters for PGE's mid-sized to large commercial customers.

For more information about the smart meter program, including an installation schedule, visit www.PortlandGeneral.com/SmartMeter.

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About Portland General Electric Company

Portland General Electric, headquartered in Portland, Ore., is a vertically integrated electric utility that serves approximately 810,000 residential, commercial and industrial customers in Oregon.

Safe Harbor Statement

Statements in this news release that relate to future plans, objectives, expectations, performance, events and the like may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements include statements concerning the future installation, deployment and operation of the smart metering system, the expected performance and benefits of the system, the expected capital cost of the system, as well as other statements identified by words including, but not limited to, "will," "anticipates," "believes," "intends," "estimates," "promises," "expects," "should," "conditioned upon" and similar expressions. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including regulatory, operational and legal matters, as well as other factors that could affect the deployment and successful operation of AMI. As a result, actual results may differ materially from those projected in the forward-looking statements. All forward-looking statements included in this news release are based on information available to the

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Company on the date hereof and such statements speak only as of the date hereof. The Company assumes no obligation to update any such forward-looking statements. Prospective investors should also review the risks and uncertainties listed in the Company's most recent Annual Report on Form 10-K and the Company's reports on Forms 8-K and 10-Q filed with the United States Securities and Exchange Commission, including Management's Discussion and Analysis of Financial Condition and Results of Operation and the risks described therein from time to time.

POR-F

Source: Portland General Electric Company

For more information, contact:

Brianne Hyder, PGE, 503-464-8442

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SOUTHERN COMPANY

News

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Feb. 26, 2009

Southern Company Installs Millionth Smart Meter

ATLANTA - Southern Company announced today that it has installed the one-millionth Smart Meter in an advanced electricity metering program for its customers across the Southeast, producing direct benefits for the customer, the environment and the company while positioning the company to employ additional features of the technology in the future.

The Smart Meter program integrates advanced metering, communications and other innovative technologies to provide superior customer service at reduced operating costs.

The meter was installed in Trussville, Ala., by the company's Alabama Power subsidiary.

The initiative began in January 2008 and will – over a five-year span – result in the deployment of more than 4.4 million meters by Southern Company's electric utility subsidiaries Alabama Power, Georgia Power, Gulf Power and Mississippi Power.

In addition to reducing operating costs that can help keep rates lower for customers, the company expects the program to lessen environmental impact. Southern Company, for example, expects to reduce the vehicle fleet used for meter reading by at least 500, saving 12.5 million miles of driving annually and producing direct benefits in lower vehicle emissions.

Once fully deployed, the Smart Meter program will also allow customers to manage energy consumption with real-time pricing signals, helping them to be more efficient with their energy use.

"Southern Company continues to be an industry leader in adopting technology that benefits customers while reducing environmental impact," said Southern Company CEO David Ratcliffe. "The company's progress in the Smart Meter program underscores our commitment to customer service and environmental responsibility."

Smart Meters can help customers understand their energy usage better. For example, a customer with a Smart Meter recently reported an unexpected energy usage increase in December. The customer service representative was able to pinpoint the day the increase began, which the customer recognized as the day his children came home from college for the holidays.

-MORE-

News

SOUTHERN COMPANY

Installing Smart Meters throughout Southern Company's territory lays the groundwork for many potential technology opportunities and benefits in the future as well. Those include:

- Innovative billing and rate options
- Remote programmability of meters
- Power quality monitoring
- Prepaid power options

Southern Company's program is based on the Sensus AMI FlexNet System, which uses advanced technology that allows for a range of features, including meter reading for monthly billing, two-way communication between customers and the company, outage detection, and remote reconnects and disconnects.

With 4.4 million customers and more than 42,000 megawatts of generating capacity, Atlanta-based Southern Company (NYSE: SO) is the premier energy company serving the Southeast. A leading U.S. producer of electricity, Southern Company owns electric utilities in four states and a growing competitive generation company, as well as fiber optics and wireless communications. Southern Company brands are known for excellent customer service, high reliability and retail electric prices that are significantly below the national average. Southern Company has been listed the top ranking U.S. electric service provider in customer satisfaction for nine consecutive years by the American Customer Satisfaction Index (ACSI). Visit our Web site at www.southerncompany.com.

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CA-IR-33

Ref: Vendors – Enspiria.

a. Please discuss the process through which Enspiria was selected by the Companies.
b. If the process used to select Enspiria was not through a bid process, please explain and justify the reasons for not relying on a bid process.
c. Assuming that the Companies relied upon a bid process to select Enspiria, please identify each of the respondents to the original bid and their bid amount. In addition, please discuss how Enspiria was selected, especially if it did not reflect the lowest bid.

HECO Companies' Response:

a. Enspiria Solutions is a well-known AMI/MDMS consulting firm that was recommended to HECO by Sensus (the Companies' AMI vendor). The Companies' selection of Enspiria was based in part on the fact that Sensus used Enspiria to provide critically needed project management resources for Portland General Electric's ("PGE") AMI project, at the request of PGE.
b. The Companies reviewed Enspiria's Qualifications and References and concluded that Enspiria was well qualified to support the Companies' need for AMI/MDMS expertise. Due to the limited scope envisioned at the time of the contract award and an interest in moving forward quickly, the Companies did not consider other consulting firms.
c. The Companies did not rely on a bid process to select Enspiria.

CA-IR-34

Ref: Vendors – Sensus.

a. Please discuss the process through which Sensus was selected by the Companies.
b. If the process used to select Sensus was not through a bid process, please explain and justify the reasons for not relying on a bid process.
c. Assuming that the Companies relied upon a bid process to select Sensus, please identify each of the respondents to the original bid and their bid amount. In addition, please discuss how Sensus was selected, especially if it did not reflect the lowest bid

HECO Companies' Response:

a. The Companies reviewed the available information for each of the prominent AMI technologies and determined that a non-mesh fixed radio frequency technology best meets the business requirements and geographical constraints for the companies. This selection process is described in Exhibit 3 of the Application. Sensus Technologies was the only AMI vendor which met those constraints.
b. The Companies did not possess sufficient internal resources to conduct a formal (and lengthy) RFP process, and decided that their selection process as described above was sufficient to justify Sensus as the AMI vendor. After Sensus was selected, the Company pursued a series of three pilots on Oahu and remained in periodic contact with other utilities who were also piloting and planning Sensus meter deployments. The AMI product marketplace has changed considerably since the Companies' technology selection and as noted in the Companies' responses to CA-IR-16.
c. The Companies did not employ a bid process.

CA-IR-35

Ref: Application.

a. Please provide any updates to the projected costs for the proposed project. If the Companies propose to update any costs, please provide support for each change and provide those updates in the same format as Exhibits 19 and 21.
b. Please provide any updates to the projected savings and/or benefits that will be derived from the proposed project. If the Companies propose to update any projected benefits/savings, please provide support for each change and provide those updates in the same format as Exhibits 19 and 21.

HECO Companies' Response:

a. The updated Exhibits 19, 21 and 22 (page 7) are submitted as Attachments 1 through 3 (respectively) of this response. All changes are documented in the "Revision Notes" section of CA-IR-2, Attachment 1. The following is a summary of the changes:

1. **Change:** Corrected the minimum TGB payment of $180,000 per month to commence January 1, 2010 for Oahu.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Section IV.E.3.

   Documentation: Described in the response to CA-IR-2, Attachment 2, Section IV.E.3.

   Requirement for Change: Required under Section 9(a)(i) of the Sensus Agreement.

2. **Change:** Corrected the Meter Reading Transportation savings to 77.22% for Oahu.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Section IX.C.6

Documentation: Described in the response to CA-IR-2, Attachment 2, Section IX.C.6

Requirement for Change: Changed the number of meters which will be replaced with AMI meters, which impacts the number of remaining non-AMI meters that will require manual reads.

3. **Change:** Revised all of the Companies AMI meter deployment to 100% of non-MV-90 meters. The meter fee reflects reduced costs due to the Network not covering all meters.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Sections II.A.4 and IV.E.3.

   Documentation: Described in the response to CA-IR-2, Attachment 2, Sections II.A.4 and IV.E.3.

   Requirement for Change: See the response to CA-IR-1 section d.

4. **Change:** Removed Project Executive Sponsor Dave Waller (P1W) hours.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Section VI.B.9.

   Documentation: Described in the response to CA-IR-2, Attachment 2, VI.B.9

   Requirement for Change: Due to company reorganization, this individual is no longer assigned to the project.

5. **Change:** Revised HELCO's 2008 meter reading costs base.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Section IX.B.2.

   Documentation: Described in the response to CA-IR-2, Attachment 2, IX.B.2.

Requirement for Change: Requested by HELCO (Paul Fujioka) as documented in Attachment 4 to this response.

6. **Change:** Revised HELCO's 2008 Field Service costs base.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Section X.B.3.

   Documentation: Described in the response to CA-IR-2, Attachment 2, X.B.3

   Requirement for Change: Requested by HELCO (Paul Fujioka), as documented in the response to CA-IR-5, Attachment 3.

7. **Change:** Revised Meter Base counts for each company to match the end of year 2008 reported meter counts.

   Implementation: Implemented in the response to CA-IR-2, Attachment 1, Section II.A.3.

   Documentation: Described in the response to CA-IR-2, Attachment 2, II.A.3.

   Requirement for Change: Refer to the response to CA-IR-5, Section b.

8. **Change:** Removed the Customer Benefits (Theft of Electricity Savings and Accuracy of Meter Savings) from the revenue requirements calculation and from the estimated surcharge calculation.

   Implementation: See attachment 1 (revised Exhibit 19 of the application) to this response.

   Documentation: See attachment 1 (revised Exhibit 19 of the application) to this response.

   Requirement for Change: The benefit of reduced system losses from energy theft reduction and the improved ability to fully bill for the amount of electricity actually being provided to customers (due to meter accuracy gains and theft reduction) is a revenue benefit that will be realized by all customers in the form of lower rates. This revenue benefit will be captured through changes in sales and trued up and passed on to the customers by means of the companies' proposed sales decoupling mechanism. As a result, these benefits will not need to be reflected/measured as part of the surcharge.

b. All proposed changes to costs and benefits are presented in a.

PROJECT COSTS AND QUANTIFIABLE BENEFITS

The following tables provide breakdown of costs and quantifiable benefits of the AMI Project as discussed in Section X.

Table 1 - AMI Implementation Costs (in $000s)

IMPLEMENTATION COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
HECO	Proj Mgmt	$843	$869	$896	$915	$0	$0	$3,523
	Meters	$0	$15,885	$16,159	$16,820	$0	$0	$48,864
	MDMS	$5,424	$4,247	$1,208	$153	$0	$0	$11,032
	Network	$54	$84	$67	$67	$16	$16	$304
	Total	$6,321	$21,085	$18,330	$17,955	$16	$16	$63,723
MECO	Proj Mgmt	$289	$298	$342	$597	$817	$0	$2,343
	Meters	$0	$0	$0	$0	$12,398	$0	$12,398
	MDMS	$1,201	$940	$268	$34	$0	$0	$2,443
	Network	$12	$3	$3	$3	$71	$0	$92
	Total	$1,502	$1,241	$613	$634	$13,286	$0	$17,276
HELCO	Proj Mgmt	$289	$285	$317	$275	$541	$555	$2,262
	Meters	$0	$0	$0	$0	$0	$15,928	$15,928
	MDMS	$1,417	$1,110	$316	$40	$0	$0	$2,883
	Network	$14	$4	$4	$4	$4	$105	$135
	Total	$1,720	$1,399	$637	$319	$545	$16,588	$21,208
TOTAL	Proj Mgmt	$1,421	$1,452	$1,555	$1,787	$1,358	$555	$8,128
	Meters	$0	$15,885	$16,159	$16,820	$12,398	$15,928	$77,190
	MDMS	$8,042	$6,297	$1,792	$227	$0	$0	$16,358
	Network	$80	$91	$74	$74	$91	$121	$531
	Total	$9,543	$23,725	$19,580	$18,908	$13,847	$16,604	$102,207

Table 2 - AMI Operating Costs (in $000s)

OPERATING COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
HECO	Proj Mgmt	$0	$0	$0	$0	$935	$954	$1,889
	Meters	$0	$16	$100	$240	$703	$765	$1,824
	MDMS	$244	$400	$407	$380	$388	$746	$2,565
	Network	$198	$268	$554	$865	$898	$932	$3,715
	Total	$442	$684	$1,061	$1,485	$2,924	$3,397	$9,993
MECO	Proj Mgmt	$0	$0	$0	$0	$0	$544	$544
	Meters	$0	$0	$0	$0	$27	$276	$303
	MDMS	$54	$89	$90	$84	$86	$165	$568
	Network	$0	$0	$0	$0	$200	$213	$413
	Total	$54	$89	$90	$84	$313	$1,198	$1,828
HELCO	Proj Mgmt	$0	$0	$0	$0	$0	$0	$0
	Meters	$0	$0	$0	$0	$0	$37	$37
	MDMS	$64	$104	$106	$99	$101	$195	$669
	Network	$0	$0	$0	$0	$0	$282	$282
	Total	$64	$104	$106	$99	$101	$514	$988
TOTAL	Proj Mgmt	$0	$0	$0	$0	$935	$1,498	$2,433
	Meters	$0	$16	$100	$240	$730	$1,078	$2,164
	MDMS	$362	$593	$603	$563	$575	$1,106	$3,802
	Network	$198	$268	$554	$865	$1,098	$1,427	$4,410
	Total	$560	$877	$1,257	$1,668	$3,338	$5,109	$12,809

Table 3 - All AMI Project Costs (in $000s)

ALL COSTS - IMPLEMENTATION & OPERATING (in		2010	2011	2012	2013	2014	2015	TOTAL
HECO	Proj Mgmt	$843	$869	$896	$915	$935	$954	$5,412
	Meters	$0	$15,901	$16,259	$17,060	$703	$765	$50,688
	MDMS	$5,668	$4,647	$1,615	$533	$388	$746	$13,597
	Network	$252	$352	$621	$932	$914	$948	$4,019
	Total	$6,763	$21,769	$19,391	$19,440	$2,940	$3,413	$73,716
MECO	Proj Mgmt	$289	$298	$342	$597	$817	$544	$2,887
	Meters	$0	$0	$0	$0	$12,425	$276	$12,701
	MDMS	$1,255	$1,029	$358	$118	$86	$165	$3,011
	Network	$12	$3	$3	$3	$271	$213	$505
	Total	$1,556	$1,330	$703	$718	$13,599	$1,198	$19,104
HELCO	Proj Mgmt	$289	$285	$317	$275	$541	$555	$2,262
	Meters	$0	$0	$0	$0	$0	$15,965	$15,965
	MDMS	$1,481	$1,214	$422	$139	$101	$195	$3,552
	Network	$14	$4	$4	$4	$4	$387	$417
	Total	$1,784	$1,503	$743	$418	$646	$17,102	$22,196
TOTAL	Proj Mgmt	$1,421	$1,452	$1,555	$1,787	$2,293	$2,053	$10,561
	Meters	$0	$15,901	$16,259	$17,060	$13,128	$17,006	$79,354
	MDMS	$8,404	$6,890	$2,395	$790	$575	$1,106	$20,160
	Network	$278	$359	$628	$939	$1,189	$1,548	$4,941
	Total	$10,103	$24,602	$20,837	$20,576	$17,185	$21,713	$115,016

Table 4 - AMI Project Management Costs (in $000s)

PROJECT MANAGEMENT (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Project Management								
Internal Labor Expense	HECO	843	869	896	915	934	954	5,411
	MECO	52	54	91	341	555	276	1,369
	HELCO	35	23	47	-	260	268	633
	Total	930	946	1,034	1,256	1,749	1,498	7,413
All Other Expense	HECO	-	-	-	-	1	-	1
	MECO	237	244	251	256	262	268	1,518
	HELCO	254	262	270	275	281	287	1,629
	Total	491	506	521	531	544	555	3,148
TOTAL	HECO	843	869	896	915	935	954	5,412
	MECO	289	298	342	597	817	544	2,887
	HELCO	289	285	317	275	541	555	2,262
	Total	1,421	1,452	1,555	1,787	2,293	2,053	10,561

Table 5 - AMI Project Meter Costs (in $000s)

METERS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
AMI Meter Material Cost								
Capital	HECO	-	10,843	10,927	11,266	256	258	33,550
	MECO	-	-	-	-	8,034	129	8,163
	HELCO	-	-	-	-	-	9,949	9,949
	Total	-	10,843	10,927	11,266	8,290	10,336	51,662
AMI Meter Installation								
Capital	HECO	-	2,523	2,618	2,778	80	82	8,081
	MECO	-	-	-	-	2,555	53	2,608
	HELCO	-	-	-	-	-	3,264	3,264
	Total	-	2,523	2,618	2,778	2,635	3,399	13,953
Damaged Meter Replacement Material								
Capital	HECO	-	-	52	157	264	319	792
	MECO	-	-	-	-	-	39	39
	HELCO	-	-	-	-	-	-	-
	Total	-	-	52	157	264	358	831
Damaged Meter Replacement Installation								
Capital	HECO	-	16	48	83	103	106	356
	MECO	-	-	-	-	27	55	82
	HELCO	-	-	-	-	-	37	37
	Total	-	16	48	83	130	198	475
Replacing Damaged Meter Sockets								
Expemse	HECO	-	2,519	2,614	2,776	-	-	7,909
	MECO	-	-	-	-	1,809	-	1,809
	HELCO	-	-	-	-	-	2,715	2,715
	Total	-	2,519	2,614	2,776	1,809	2,715	12,433
TOTAL	HECO	-	15,901	16,259	17,060	703	765	50,688
	MECO	-	-	-	-	12,425	276	12,701
	HELCO	-	-	-	-	-	15,965	15,965
	Total	-	15,901	16,259	17,060	13,128	17,006	79,354

Table 6 - AMI Network Costs (in $000s)

AMI COMMUNICATIONS NETWORK (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
FNP/ERP Material & Installation								
Capital	HECO	-	68	51	51	-	-	170
	MECO	-	-	-	-	68	-	68
	HELCO	-	-	-	-	-	101	101
	Total	-	**68**	**51**	**51**	**68**	**101**	**339**
Sensus FlexNet Network Lease								
Expense	HECO	198	268	554	865	898	932	3,715
	MECO	-	-	-	-	200	210	410
	HELCO	-	-	-	-	-	282	282
	Total	**198**	**268**	**554**	**865**	**1,098**	**1,424**	**4,407**
Sensus Additional Options								
Expense	HECO	54	16	16	16	16	16	134
	MECO	12	3	3	3	3	3	27
	HELCO	14	4	4	4	4	4	34
	Total	**80**	**23**	**23**	**23**	**23**	**23**	**195**
TOTAL	HECO	252	352	621	932	914	948	4,019
	MECO	12	3	3	3	271	213	505
	HELCO	14	4	4	4	4	387	417
	Total	**278**	**359**	**628**	**939**	**1,189**	**1,548**	**4,941**

Table 7 – AMI MDMS Costs by Phases (in $000s)

MDMS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
MDMS Hardware and Operating System (including AFUDC)								
Capital	HECO	417	265	-	-	-	344	**1,026**
	MECO	93	59	-	-	-	76	**228**
	HELCO	110	70	-	-	-	90	**270**
	Total	**620**	**394**	**-**	**-**	**-**	**510**	**1,524**
Phase I - Basic CIS and RNI Integration (including AFUDC)								
Deferred	HECO	4,252	-	-	-	-	-	**4,252**
	MECO	940	-	-	-	-	-	**940**
	HELCO	1,110	-	-	-	-	-	**1,110**
	Total	**6,302**	**-**	**-**	**-**	**-**	**-**	**6,302**
Phase II - Additional Integration Tasks (including AFUDC)								
Deferred	HECO	-	3,276	-	-	-	-	**3,276**
	MECO	-	724	-	-	-	-	**724**
	HELCO	-	855	-	-	-	-	**855**
	Total	**-**	**4,855**	**-**	**-**	**-**	**-**	**4,855**
Phase III - Additional Customization (including AFUDC)								
Deferred	HECO	-	-	904	-	-	-	**904**
	MECO	-	-	201	-	-	-	**201**
	HELCO	-	-	236	-	-	-	**236**
	Total	**-**	**-**	**1,341**	**-**	**-**	**-**	**1,341**
MDMS Software License Fee								
Deferred	HECO	215	167	167	153	-	-	**702**
	MECO	48	37	37	34	-	-	**156**
	HELCO	56	44	44	40	-	-	**184**
	Total	**319**	**248**	**248**	**227**	**-**	**-**	**1,042**
Training, Process & Change Management								
Expense	HECO	540	539	137	-	-	-	**1,216**
	MECO	120	120	30	-	-	-	**270**
	HELCO	141	141	36	-	-	-	**318**
	Total	**801**	**800**	**203**	**-**	**-**	**-**	**1,804**
Support and Maintenance								
Expense	HECO	244	400	407	380	388	402	**2,221**
	MECO	54	89	90	84	86	89	**492**
	HELCO	64	104	106	99	101	105	**579**
	Total	**362**	**593**	**603**	**563**	**575**	**596**	**3,292**
TOTAL	Capital	620	394	-	-	-	510	**1,524**
	Deferred	6,621	5,103	1,589	227	-	-	**13,540**
	Expense	1,163	1,393	806	563	575	596	**5,096**
	Total	**8,404**	**6,890**	**2,395**	**790**	**575**	**1,106**	**20,160**

Table 8 – AMI MDMS Costs by Accounting Stages (in 000s)

MDMS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
STAGE 1 - Preliminatry Project Stage								
Expense	HECO	All Stage 1 MDMS costs are expensed within the 2009 Budget Year						
	MECO							
	HELCO							
	Total	-	-	-	-	-	-	-
STAGE 2 - Application Development Stage								
Deferred (including AFUDC)	HECO	4,467	3,443	1,071	153	-	-	9,134
	MECO	988	761	238	34	-	-	2,021
	HELCO	1,166	899	280	40	-	-	2,385
	Total	**6,621**	**5,103**	**1,589**	**227**	-	-	**13,540**
Expense	HECO	540	539	137	-	-	-	1,216
	MECO	120	120	30	-	-	-	270
	HELCO	141	141	36	-	-	-	318
	Total	**801**	**800**	**203**	-	-	-	**1,804**
Total		**7,422**	**5,903**	**1,792**	**227**	-	-	**15,344**
STAGE 3 - Post Implementation/Operation Stage								
Expense	HECO	244	400	407	380	388	402	2,221
	MECO	54	89	90	84	86	89	492
	HELCO	64	104	106	99	101	105	579
	Total	**362**	**593**	**603**	**563**	**575**	**596**	**3,292**
Capital (including AFUDC)	HECO	417	265	-	-	-	344	1,026
	MECO	93	59	-	-	-	76	228
	HELCO	110	70	-	-	-	90	270
	Total	**620**	**394**	-	-	-	**510**	**1,524**
TOTAL	HECO	5,668	4,647	1,615	533	388	746	13,597
	MECO	1,255	1,029	358	118	86	165	3,011
	HELCO	1,481	1,214	422	139	101	195	3,552
	Total	**8,404**	**6,890**	**2,395**	**790**	**575**	**1,106**	**20,160**

Table 9 – AMI Capital Costs (in $000s)

CAPITAL COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Meters								
AMI Meter Materia	HECO	-	10,843	10,927	11,266	256	258	**33,550**
	MECO	-	-	-	-	8,034	129	**8,163**
	HELCO	-	-	-	-	-	9,949	**9,949**
	Total	**-**	**10,843**	**10,927**	**11,266**	**8,290**	**10,336**	**51,662**
AMI Meter Installation	HECO	-	2,523	2,618	2,778	80	82	**8,081**
	MECO	-	-	-	-	2,555	53	**2,608**
	HELCO	-	-	-	-	-	3,264	**3,264**
	Total	**-**	**2,523**	**2,618**	**2,778**	**2,635**	**3,399**	**13,953**
Damaged Meter Replacement Material	HECO	-	-	52	157	264	319	**792**
	MECO	-	-	-	-	-	39	**39**
	HELCO	-	-	-	-	-	-	**-**
	Total	**-**	**-**	**52**	**157**	**264**	**358**	**831**
Damaged Meter Replacement Installation	HECO	-	16	48	83	103	106	**356**
	MECO	-	-	-	-	27	55	**82**
	HELCO	-	-	-	-	-	37	**37**
	Total	**-**	**16**	**48**	**83**	**130**	**198**	**475**
MDMS Development & Implementation								
MDMS Hardware & Oper. System (incl. AFUDC)	HECO	417	265	-	-	-	344	**1,026**
	MECO	93	59	-	-	-	76	**228**
	HELCO	110	70	-	-	-	90	**270**
	Total	**620**	**394**	**-**	**-**	**-**	**510**	**1,524**
AMI Communications Network								
FNP/FRP Material & Installation	HECO	-	68	51	51	-	-	**170**
	MECO	-	-	-	-	68	-	**68**
	HELCO	-	-	-	-	-	101	**101**
	Total	**-**	**68**	**51**	**51**	**68**	**101**	**339**
TOTAL	HECO	417	13,715	13,696	14,335	703	1,109	**43,975**
	MECO	93	59	-	-	10,684	352	**11,188**
	HELCO	110	70	-	-	-	13,441	**13,621**
	Total	**620**	**13,844**	**13,696**	**14,335**	**11,387**	**14,902**	**68,784**

Table 10 – AMI Deferred Costs (in $000s)

DEFERRED COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
MDMS Development & Implementation								
MDMS Application SW License Fees	HECO	215	167	167	153	-	-	702
	MECO	48	37	37	34	-	-	156
	HELCO	56	44	44	40	-	-	184
	Total	319	248	248	227	-	-	1,042
Phase 1 MDMS SW (incl. AFUDC)	HECO	4,252	-	-	-	-	-	4,252
	MECO	940	-	-	-	-	-	940
	HELCO	1,110	-	-	-	-	-	1,110
	Total	6,302	-	-	-	-	-	6,302
Phase 2 MDMS SW (incl. AFUDC)	HECO	-	3,276	-	-	-	-	3,276
	MECO	-	724	-	-	-	-	724
	HELCO	-	855	-	-	-	-	855
	Total	-	4,855	-	-	-	-	4,855
Phase 3 MDMS SW (incl. AFUDC)	HECO	-	-	904	-	-	-	904
	MECO	-	-	201	-	-	-	201
	HELCO	-	-	236	-	-	-	236
	Total	-	-	1,341	-	-	-	1,341
TOTAL DEFERRED	HECO	4,467	3,443	1,071	153	-	-	9,134
	MECO	988	761	238	34	-	-	2,021
	HELCO	1,166	899	280	40	-	-	2,385
	Total	6,621	5,103	1,589	227	-	-	13,540

Table 11 – AMI Expense Costs (in $000s)

EXPENSE COSTS (in $000s)		2010	2011	2012	2013	2014	2015	TOTAL
Project Planning, Design, and Approval								
Project Management	HECO	843	869	896	915	935	954	**5,412**
	MECO	289	298	342	597	817	544	**2,887**
	HELCO	289	285	317	275	541	555	**2,262**
	Total	**1,421**	**1,452**	**1,555**	**1,787**	**2,293**	**2,053**	**10,561**
Meters								
Replacing Damaged Meter Sockets	HECO	-	2,519	2,614	2,776	-	-	**7,909**
	MECO	-	-	-	-	1,809	-	**1,809**
	HELCO	-	-	-	-	-	2,715	**2,715**
	Total	-	**2,519**	**2,614**	**2,776**	**1,809**	**2,715**	**12,433**
MDMS Development & Implementation								
Training, Process & Change Management	HECO	540	539	137	-	-	-	**1,216**
	MECO	120	120	30	-	-	-	**270**
	HELCO	141	141	36	-	-	-	**318**
	Total	**801**	**800**	**203**	-	-	-	**1,804**
Support & Maintenance	HECO	244	400	407	380	388	402	**2,221**
	MECO	54	89	90	84	86	89	**492**
	HELCO	64	104	106	99	101	105	**579**
	Total	**362**	**593**	**603**	**563**	**575**	**596**	**3,292**
AMI Communications Network								
Sensus FlexNet Network	HECO	198	268	554	865	898	932	**3,715**
	MECO	-	-	-	-	200	210	**410**
	HELCO	-	-	-	-	-	282	**282**
	Total	**198**	**268**	**554**	**865**	**1,098**	**1,424**	**4,407**
Sensus Additional Options	HECO	54	16	16	16	16	16	**134**
	MECO	12	3	3	3	3	3	**27**
	HELCO	14	4	4	4	4	4	**34**
	Total	**80**	**23**	**23**	**23**	**23**	**23**	**195**
TOTAL EXPENSED	HECO	1,879	4,611	4,624	4,952	2,237	2,304	**20,607**
	MECO	475	510	465	684	2,915	846	**5,895**
	HELCO	508	534	463	378	646	3,661	**6,190**
	Total	**2,862**	**5,655**	**5,552**	**6,014**	**5,798**	**6,811**	**32,692**

Table 12 – AMI Quantifiable Benefits (in $000s)

QUANTIFIABLE BENEFITS (in $000s)			2010	2011	2012	2013	2014	2015	TOTAL
[1] O&M Reduction	Meter Reading Savings	HECO	-	-	1,164	2,448	3,430	3,533	10,575
		MECO	-	-	-	-	-	1,000	1,000
		HELCO	-	-	-	-	-	-	-
		Total	-	-	1,164	2,448	3,430	4,533	11,575
	Field Service Savings	HECO	-	165	339	526	1,084	1,116	3,230
		MECO	-	-	-	-	178	367	545
		HELCO	-	-	-	-	-	220	220
		Total	-	165	339	526	1,262	1,703	3,995
Customer Benefit	Theft of Electricity Savings	HECO	-	290	886	1,493	1,813	1,831	6,313
		MECO	-	-	-	-	224	454	678
		HELCO	-	-	-	-	260	529	789
		Total	-	290	886	1,493	2,297	2,814	7,780
	Accuracy of Meter Savings	HECO	276	846	1,425	1,730	1,747	1,764	7,788
		MECO	-	-	-	-	243	494	737
		HELCO	-	-	-	-	-	317	317
		Total	276	846	1,425	1,730	1,990	2,575	8,842
Future Capital Reduction	Meter Capital Savings	HECO	-	421	524	637	714	751	3,047
		MECO	-	-	-	-	179	218	397
		HELCO	-	-	-	-	-	238	238
		Total	-	421	524	637	893	1,207	3,682
TOTAL QUANTIFIABLE BENEFITS		HECO	276	1,722	4,338	6,834	8,788	8,995	30,953
		MECO	-	-	-	-	824	2,533	3,357
		HELCO	-	-	-	-	260	1,304	1,564
		Total	276	1,722	4,338	6,834	9,872	12,832	35,874

[1] Only O&M Reduction Benefits flow through the Surcharge

EXHIBIT 21 - Rate Impact of AMI

Hawaiian Electric Company, Inc.

	2010	2011	2012	2013	2014	2015
Rev Requirement ($000)	6,415	11,990	14,585	11,743	8,405	7,548
Sales Forecast (GWH)	7,464.5	7,505.8	7,608.4	7,727.1	7,850.0	7,974.9
AMI Surcharge (¢/kWh):	**0.0859**	**0.1597**	**0.1917**	**0.1520**	**0.1071**	**0.0946**

Sales Forecast:
Yrs 2010 - 2013: Forecast Division based on September 2008 Forecast.
Yrs 2014 - 2015: Forecast Division based on escalated growth rate from August 2007 LT Forecast.

Hawaii Electric Light Company, Inc.

	2010	2011	2012	2013	2014	2015
Rev Requirement ($000)	2,563	2,744	2,654	2,479	2,308	5,374
Sales Forecast (GWH)	1,161.4	1,184.4	1,210.8	1,240.8	1,264.6	1,282.7
AMI Rate Impact (¢/kWh):	**0.2207**	**0.2317**	**0.2192**	**0.1998**	**0.1825**	**0.4190**

Sales Forecast:
Yrs 2010 - 2013: Forecast Division based on September 2008 Forecast.
Yrs 2014 - 2015: Generation Planning extrapolated forecast.

Maui Electric Company, Ltd. (Maui Division)

	2010	2011	2012	2013	2014	2015
Rev Requirement ($000)	1,839	2,030	1,991	1,879	4,111	2,237
Sales Forecast (GWH)	1,200.5	1,236.2	1,276.8	1,297.4	1,323.4	1,352.0
AMI Rate Impact (¢/kWh):	**0.1532**	**0.1642**	**0.1559**	**0.1448**	**0.3106**	**0.1655**

Sales Forecast:
Yrs 2010 - 2015: Forecast Division based on September 2008 Forecast.

Source:
Revenue Requirement: Finanical Analysis Division
Total project revenue requirement less imputed debt and rebalancing costs and internal labor.

HECO COMPANIES NET INCREMENTAL REVENUE REQUIREMENT CALCULATION

	Year	Project Mgmt	Replace/ Retire Existing Meters	New Meter Installation	MDMS Deferred SW Development	MDMS Capital & Expense	Damaged Socket Replacement	AMI Network: AMI Network Cap & Exp	AMI Network: Imputed Debt	AMI Network: Total Rev. Reqmt.	Direct Benefits: Field Service Savings	Direct Benefits: Meter Reading Savings	TOTAL: Revenue Requirements
		A	B	C	D	E	F	G	H	I = G+H	J	K	A+B+C+D+E+F+I +J+K
HECO AMI													
Revenue Requirements - SURCHARGE REVENUE REQUIREMENT ($000)													
1	2010	-	4,918	-	329	891	-	277		277	-	-	6,415
2	2011	-	4,710	1,893	1,273	1,216	2,764	316		316	(181)	-	11,990
3	2012	-	4,320	5,709	1,825	856	2,869	655		655	(372)	(1,277)	14,585
4	2013	-	(969)	9,357	1,901	657	3,047	1,015		1,015	(578)	(2,687)	11,743
5	2014	1	(1,041)	10,881	1,815	639	-	1,065		1,065	(1,190)	(3,765)	8,405
6	2015	1	(925)	10,228	1,707	545	-	1,096		1,096	(1,225)	(3,877)	7,548
Total		2	11,013	38,069	8,848	4,803	8,680	4,424	-	4,424	(3,546)	(11,606)	60,685
MECO AMI													
Revenue Requirements - SURCHARGE REVENUE REQUIREMENT ($000)													
1	2010	260	1,296	-	73	198	-	13		13	-	-	1,839
2	2011	268	1,207	-	281	270	-	4		4	-	-	2,030
3	2012	276	1,118	-	403	190	-	4		4	-	-	1,991
4	2013	282	1,027	-	420	146	-	4		4	-	-	1,879
5	2014	287	(239)	1,500	401	142	1,986	229		229	(195)	-	4,111
6	2015	293	(353)	3,037	378	121	-	261		261	(402)	(1,098)	2,237
Total		1,666	4,056	4,537	1,957	1,065	1,986	514	-	514	(598)	(1,098)	14,086
HELCO AMI													
Revenue Requirements - SURCHARGE REVENUE REQUIREMENT ($000)													
1	2010	279	1,950	-	86	233	-	16		16	-	-	2,563
2	2011	287	1,802	-	332	317	-	4		4	-	-	2,744
3	2012	296	1,654	-	476	224	-	4		4	-	-	2,654
4	2013	302	1,505	-	496	172	-	4		4	-	-	2,479
5	2014	308	1,355	-	474	167	-	4		4	-	-	2,308
6	2015	315	(468)	1,880	445	142	2,980	321		321	(242)	-	5,374
Total		1,788	7,798	1,880	2,309	1,255	2,980	355	-	355	(242)	-	18,122

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EXHIBIT 22
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	HELCO 2008 Application	HELCO 2008 Revised	HELCO 2008 Change	2004 Recorded	2005 Recorded	2006 Recorded	2007 Recorded	2008 Recorded
Manual Meter Reading Costs (without AMI)								
Labor Costs (BU, incl. overhead 421)	814.1	630.0	(184.1)	527.8	479.2	529.4	528.4	557.8
Labor Overhead 406, 422, 423		290.9	290.9	191.1	213.1	301.0	270.7	269.5
Labor Costs (merit, incl. overhead)	-		-					
Non-Labor Costs (incl. materials & supplies, excl. Outside Services)	5.4	6.3	0.8	11.4	10.7	8.6	19.6	4.2
Transportation Costs	84.1	94.2	10.1	125.8	113.6	133.5	116.8	155.2
Outside Services	48.2	39.3	(8.9)	25.9	45.1	36.6	18.8	64.6
Total Manual Meter Reading Costs (without AMI)	951.8	1,060.6	108.8	882.1	861.7	1,009.1	954.2	1,051.3

NOTE: The Field Services O&M Costs used for the application is being revised utilizing the 2008 recorded costs as a more reasonable estimate.
The original costs included in the application utilized the Pillar files for 2008 budget, which needed to be allocated between field service work and customer service office work (primarily call center).

CA-IR-36

Ref: Application.

The Company is requesting the approval of an AMI surcharge to the extent that costs related to the AMI project are not recovered through base rates or through another surcharge.

a. Please provide a detailed description of the accounting procedures that will be used to track each of the proposed costs associated with the AMI project and the supporting documentation that will be maintained to confirm the relation of the cost to the AMI project and the proper classification of the cost as a capital item, expense, deferred, etc. The Companies' response should include, but not be limited to, copies of the procedures that will be followed, identification of the accounts and codes that will be used to track the costs, and the journal entries that might be used to record any applicable transactions.
b. Please provide a detailed description of the accounting procedures that will be used to track the revenues collected by the Companies through base rates and any surcharges and the steps that will be taken to ensure that the Company that does not recover more than the allowed reasonable costs associated with the AMI project. The Companies response should include, but not be limited to, copies of the procedures that will be followed, identification of the accounts and codes that will be used to track the revenues received, and the journal entries that might be used to record any applicable transactions.
c. Please confirm that, to the extent that the Company will recover any AMI costs through a surcharge, it will be the net amount of costs offset by any savings that can be attributed to the AMI project.
    1. Please provide a detailed description of the procedures that will be used to track the savings that can be attributed to the AMI project.
    2. Please provide a detailed description of how the Companies will apply the savings generated by the AMI project to costs that might be recovered through any mechanism other than base rates. The Companies response should include, but not be limited to, copies of the procedures that will be followed, identification of the accounts and codes that will be used to track the revenues received, and the journal entries that might be used to support the amounts to be recovered and/or returned (if savings exceed costs for any given period) through a surcharge.

HECO Companies' Response:

a. The Company is in the process of creating various capital, deferred and expensed project numbers and workorders to properly capture the AMI project's recorded costs so that the journal entries, with respect to accounting for the recoveries of these costs, are accurately calculated and recorded in accordance with the AMI application. Refer to Attachment 1 for preliminary (and subject to change based on additional analyses, discussions, guidance, proceeding progress and/or receipt of Commission decisions and orders in this proceeding) accounting guidelines as to how the incremental costs (including incremental net benefits) will be recorded.

b. Refer to the Company's response to part (a).

c. Confirmed. The recovery of the incremental AMI project costs will be net of the incremental quantifiable benefits created by the AMI project which are not captured in base rates or any other surcharge mechanism.

1. Surcharge Impacts: Only those benefits which impact O&M expenses will be used in the surcharge calculation. These benefits are the Reduction in Meter Reading O&M ("MR Benefits") and Reduction in Field Service O&M ("FS Benefits"). The calculation for the estimations of the MR Benefits and the FS Benefits are performed in the Companies' response to CA-IR-2 Attachment 1, Sections IX and X. The narratives describing these calculations are provided in the Companies' response to CA-IR-2 Attachment 2, Sections IX and X. This method will be used to develop the estimated MR Benefits and FS Benefits for the surcharge mechanism. The actual costs for these areas will be tracked against their original budgets (without AMI implementation) to recognize the AMI benefits. Any actual expenditure deviations within these budgets that do not specially pertain to the implementation of AMI will need to be documented as well. The documented MR Benefits and FS Benefits will be used in the true up calculation as discussed in Section XI.2 of the AMI application.

Other Tracking and Reporting:

- Meter Reader Manning Reduction: The Companies' response to CA-IR-6, Attachment 1 provides the Companies' estimated reduction in meter reader manning. The Companies will track and report their efforts and status on the reduction of the meter reader manpower.

- Field Service Manning Reduction: Attachment 2 to this response provides the Companies' estimated reduction in field service manning. The Companies will track and report their efforts and status on the reduction of the field service manpower
- Customer Benefits: Customer Benefits include the "Theft of Electricity Savings" benefits (Theft) and the "Accuracy of Meter Savings" benefits (Accuracy). These benefits result in higher sales and thus higher revenues, and would flow to the Companies' customers through the proposed revenue balancing account in the sales decoupling mechanism, if approved by the Commission (Decoupling Proceeding, Docket No. 2008-0274). Each company currently tracks the annual results from its Revenue Protection efforts. Attachment 3 to this response shows a HECO report for its Revenue Protection. Each company will alter its tracking and reporting to specifically denote theft which was recognized through the capabilities provided by the AMI system.
- Meter Capital Savings: The Companies will track and report their reduction in Meter Capital Expenditures from their pre-existing programs by comparing their actual expenditures to their original Capital expenditure expectations (without AMI implementation).

2. Refer to the Company's response to part (a).

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(Updated as of June 5, 2009)

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THE FOLLOWING ARE PROPOSED ACCOUNTING GUIDELINES TO ACCOUNT FOR THE VARIOUS COST COMPONENTS OF THE AMI PROJECT AND THE RECOVERY OF THOSE COSTS FROM THE AMI SURCHARGE. THESE PROPOSED GUIDELINES ARE PRELIMINARY ONLY AND SUBJECT TO CHANGE UPON ADDITIONAL ANALYSIS, DISCUSSION, GUIDANCE, PROCEEDING PROGRESS AND/OR RECEIPTS OF COMMISSION DECISION AND ORDERS IN DOCKET NO. 2008-0303.

The following general accounting guidelines, which include sample journal entries, are provided to assist in the recordation of the components of HECO, HELCO and MECO's (Companies) AMI project (Docket No. 2008-0303), as discussed in Section XI, "AMI Surcharge, Accounting and Cost Recovery" and Exhibit 24 of the Companies' AMI Application. These guidelines are for the period when the incremental revenue requirements for the AMI project costs are recovered through the AMI surcharge (or other surcharge). When the incremental revenue requirements are fully reflected in base rates, certain accounting entries will be revised. These guidelines will be revised from time to time, as needed, to provide additional clarification. The sample journal entries are numbered for reference purposes.

The AMI is a metering system that will record customer consumption (and possibly other parameters) hourly or more frequently and transmit that information of measurements over a communication network to a central collection point, where the utilities can store and analyze the information for the benefit of ratepayers and the utilities. The Companies have submitted an application to the PUC for approval to proceed with the project and to recover the net incremental costs of this project from its ratepayers through an AMI or similar-type surcharge (AMI surcharge). The AMI project will include the following incremental cost components and offsetting incremental benefits (refer to Section XI, "AMI Surcharge, Accounting and Cost Recovery" and Exhibit 24 of the AMI Application for more information on each cost component and benefit below):

- New AMI meters
- Existing Non-AMI Meters
- MDMS Capital Costs
- MDMS Deferred Software Development Costs
- MDMS-Related Expenses
- AMI Network Capital Costs
- AMI Network Lease Costs
- AMI Network-Related Expenses
- Other AMI-Related Costs – Damaged Meter Socket Costs
- Other AMI-Related Costs – Outside Consulting Costs
- Offsetting Incremental Benefits – Energy Theft Recovery, Meter Accuracy Gains, Meter Reading Savings and Field Services Savings

AMI SURCHARGE REVENUES

The proposed AMI surcharge is expected to commence on January 1, 2010, following Commission approval of the AMI Project and AMI surcharge. The AMI surcharge would recover the revenue requirements of the net incremental project costs (as listed above) on a prospective basis (based on the forecast of the AMI project cost revenue requirements for the year), subject to annual reconciliations of actual costs and actual revenues[1]. Upon commencement, on a monthly basis, the revenues from the AMI surcharge would be automatically recorded by the Company's customer service ACCESS system. Revenues are recorded, as the surcharge is applied to customers' bills, via the following entry:

JE #1 Dr. Customer billed receivables
Cr. AMI surcharge revenues by rate schedule (for each cost component listed above)

The AMI surcharge revenues will include recoveries of the revenue requirements related to the net incremental AMI project costs, which will consist of project costs, taxes and return on investment amounts, and offset by costs savings related to the project.

NEW AMI METERS

New AMI meters are planned for installation at HECO beginning 2011 over 3 years, at MECO beginning *in 2014 over 1 year, and at HELCO beginning in 2015 over 1 year. For book accounting purposes, the* Companies will capitalize the installed costs of the new AMI meters upon installation and include the meters as utility assets, and depreciate the new AMI meters over the current PUC-approved depreciation rate for meters, beginning January 1 of the following year the meters are placed into service. For ratemaking purposes, the Companies plan to include the new meters in rate base and to recover the costs of these new AMI meters, including their installation costs, via an AMI surcharge over 7 years from the year of installation. This represents an accelerated recovery of the Companies' investment in these new AMI meters.

<u>New AMI Meters Installation:</u>
The Company will create workorders to track and accumulate the new AMI meter costs, including their installation. AFUDC will not be applied to the costs of the newly installed meters as the new meters will be recorded to the Company's plant-in-service accounts in the month installed. The following monthly entries will be recorded by Property Accounting (in the same month), as new meters are installed. This methodology is consistent with the installation of the Company's non-AMI meters.

JE #2 Dr. Construction work-in-progress workorders – AMI meters
Cr. Accounts payable
The purpose of this entry is to accumulate the installed costs of the new AMI meters installed during the month.

JE #3 Dr. Plant-in-service – new AMI meters
Cr. Construction work-in-progress

1 The following illustrates the expected pattern of AMI surcharges and adjustments following Commission approval of the AMI project:
- Initial surcharge – January 1, 2010
- Second year surcharge – January 1, 2011
- Reconciliation of first year surcharge – March 1, 2011 (includes both reconciliation plus second year surcharge that was effective January 1, 2011)

GENERAL ACCOUNTING GUIDELINES FOR THE
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This entry will be recorded at the end of each month to record the new AMI meters into the Company's plant-in-service accounts.

New AMI Meters Depreciation:
This monthly recurring journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting), beginning January 1 of the following year the new AMI meters are placed into service, as part of the Company's monthly depreciation entries, however book depreciation will be tracked separately for the new AMI meters. The depreciation expense will be based on current PUC-approved depreciation rates for meters and on the ending new AMI meter in-service balance of the previous year.

JE #4	Dr.	Depreciation expense – new AMI meters
	Cr.	Accumulated depreciation

New AMI Meters Cost Recovery:
As mentioned above, the Companies plan to recover the costs of the new AMI meters, including their installation costs, via an AMI surcharge over 7 years from the year of installation – beginning 2011 for HECO, 2014 for MECO and 2015 for HELCO. There will be a timing difference with respect to the cost recovery and depreciation of the new AMI meters since cost recovery will commence in the year of installation and recovered over 7 years, while depreciation will commence in the year following installation and be based on current approved depreciation rates. Therefore, the Companies' will monitor this timing difference on a monthly basis. A manual monthly journal entry will be recorded by Corporate Accounting to set-up a regulatory liability (for the advanced recovery of the AMI meters) in order to defer the AMI surcharge revenues (originally recorded in JE #1), until recognized together with the depreciation expenses:

JE #5	Dr.	AMI surcharge revenues by rate schedule – new AMI meters
	Cr.	Regulatory liability –new AMI meters

As the new meters are depreciated, the below monthly journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting) to reduce the regulatory liability account (set-up in JE #5) and recognize revenues in an amount equivalent to the new AMI meter depreciation expense (JE #4) recorded at that time. The entry will coincide with the depreciation expense entry (JE #4) above. The regulatory liability related to the new AMI meters will build up during the 7-year recovery period and decrease over time as the new meters are depreciated.

JE #6	Dr.	Regulatory liability –new AMI meters
	Cr.	AMI surcharge revenues by rate schedule – new AMI meters

The creation of any deferred tax liability (or asset) as a result of accounting for the new AMI meters will be included as a deduction to rate base (addition if deferred tax asset).

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the new AMI meters would be adjusted based on the results of the reconciliation and would represent the advanced cost recovery to-

date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the new AMI meter expenditures to the previous year's actual revenue requirements related to the new AMI meter cost recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

EXISTING NON-AMI METERS

Existing non-AMI meters will be retired from service upon the installation of new AMI meters. As previously noted in the new AMI meter section, all new AMI meters at HECO are planned to be installed over a three-year period beginning 2011. Accordingly, all existing non-AMI meters would be retired over the same three-year period. For book accounting purposes, the Companies will continue to depreciate the non-AMI meters over the current PUC-approved depreciation rates for meters until retired from service. For rate-making purposes, the Companies propose to recover the net book value (as of December 31, 2009) of the existing non-AMI meters via the AMI surcharge over 3 years beginning January 1, 2010 following Commission approval of the AMI Project and AMI surcharge. As such, the following entries are required to account for the timing of the removal and recovery of the existing non-AMI meters.

Existing Non-AMI Meters Depreciation:
This monthly recurring journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting) as part of the Company's monthly depreciation entries, however book depreciation will be tracked separately for non-AMI meters. Depreciation will be recorded only on the remaining non-AMI meters that have not been retired from service. The depreciation expense will continue to be based on current PUC-approved depreciation rates for meters and on the ending remaining non-AMI meter in-service balance of the previous year. This entry would not be necessary after the third year of deployment assuming all non-AMI meters are retired over a 3-year deployment period.

JE #7 Dr. Depreciation expense – existing non-AMI meters
Cr. Accumulated depreciation

Existing Non-AMI Meters Recovery:
As mentioned above, the Companies plan to recover the remaining costs of the existing non-AMI meters, via the AMI surcharge over 3 years beginning January 1, 2010, following Commission approval of the AMI Project and AMI surcharge. There will be a timing difference with respect to the cost recovery and depreciation/retirement of the existing non-AMI meters since retirement of these meters will not begin until 2011 (for HECO). Therefore, a manual journal monthly entry will be recorded by Corporate Accounting to set-up a regulatory liability (for the advanced recovery of the non-AMI meters) in order to defer the AMI surcharge revenues (originally recorded in JE #1), until recognized together with the depreciation expenses and retirement of the existing non-AMI meters.

JE #8 Dr. AMI surcharge revenues by rate schedule – NBV of existing non-AMI meters
Cr. Regulatory liability – NBV of existing non-AMI meters

The below monthly journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting) to reduce the regulatory liability account (set up in JE #8) and recognize revenues in an amount equivalent to the depreciation expense (JE #7) of the non-AMI meters recorded at that time. The entry will coincide with the depreciation expense entry (JE #7) above.

JE #9 Dr. Regulatory liability – NBV of existing non-AMI meters
Cr. AMI surcharge revenues by rate schedule – NBV of existing non-AMI meters

The below annual manual journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting) for the retirement of the non-AMI meters. This entry will record the removal of the original cost of the non-AMI meters, including accumulated depreciation. The net book value of the removed non-AMI meters will reduce the regulatory liability (set-up in JE #8).

JE #10 Dr. Accumulated depreciation (on meters that were retired)
Dr. Regulatory liability – NBV of the meters that were retired
Cr. Non-AMI meters retired

The regulatory liability related to the existing non-AMI meters will build up in the first year of recovery (JE #8) and decrease as the existing non-AMI meters are depreciated (JE #9) and retired from service (JE #10). The regulatory liability related to the existing non-AMI meters should be zero upon the removal and replacement of the last non-AMI meter.

The creation of any deferred tax liability (or asset) as a result of accounting for the non-AMI meters will be included as a deduction to rate base (addition if deferred tax asset).

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the non-AMI meters would be adjusted based on the results of the reconciliation and would represent the advanced cost recovery to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the non-AMI meter retirements to the previous year's actual revenue requirements related to the non-AMI meter recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

MDMS CAPITAL COSTS

For book accounting purposes, the Companies propose to capitalize the installed costs of the MDMS computer hardware and depreciate the MDMS computer hardware over the current PUC-approved depreciation rate for computer hardware, beginning January 1 of the following year the computer hardware is placed into service. The Companies propose that ratemaking treatment follow book accounting treatment.

MDMS Capital Purchase:
The Company will create a workorder to track and capture the MDMS computer hardware purchase. AFUDC will not be applied to the costs of the purchased MDMS computer hardware as the computer hardware will be recorded to the Company's plant-in-service accounts in the month purchased. The following monthly entries will be recorded by Property Accounting (in the same month), to record the MDMS computer hardware purchase. This methodology is consistent with the Company's procedure of purchasing computer hardware.

JE #11 Dr. Construction work-in-progress workorder – MDMS computer hardware
Cr. Accounts payable
The purpose of this entry is to capture the cost of the MDMS computer hardware purchase.

JE #12 Dr. Plant-in-service – MDMS computer hardware
Cr. Construction work-in-progress
This entry is recorded at the end of the month to record the MDMS computer hardware into the Company's plant-in-service accounts.

MDMS Computer Hardware Depreciation:
This monthly recurring journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting), beginning January 1 of the following year the MDMS computer hardware is placed into service, as part of the Company's monthly depreciation entries, however will be tracked separately for the MDMS computer hardware. The depreciation expense will be based on current PUC-approved depreciation rates for computer hardware and on the ending computer hardware in-service balance of the previous year.

JE #13 Dr. Depreciation expense – MDMS computer hardware
Cr. Accumulated depreciation

MDMS Computer Hardware Recovery:
The Companies plan to recover the MDMS computer hardware costs, via the AMI surcharge, following Commission approval of the AMI Project and AMI surcharge. As previously mentioned above, the Companies propose that ratemaking treatment follow book accounting treatment (i.e., the recovery of the MDMS computer hardware will occur as the MDMS computer hardware is depreciated).

If the monthly AMI surcharge revenues related to MDMS-computer hardware recovery (JE #1) are LESS than the monthly actual depreciation expenses (JE #13), then this monthly entry will be recorded for the difference:

JE #14 Dr. Regulatory liability[2] – MDMS-computer hardware

[2] The debit of this entry would normally be to a regulatory asset account. However, for the purposes of simplifying the record-keeping (since the difference may positive or negative every month) and to

Cr. Depreciation expense – MDMS computer hardware

If the monthly AMI surcharge revenues related to MDMS-computer hardware recovery (JE #1) are MORE than monthly actual depreciation expenses (JE #13), then this monthly entry will be recorded for the difference:

JE #15 Dr. AMI surcharge revenues by rate schedule – MDMS-computer hardware
Cr. Regulatory liability – MDMS-computer hardware

The creation of any deferred tax liability (or asset) as a result of accounting for the MDMS computer hardware will be included as a deduction to rate base (addition if deferred tax asset).

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded the entries above. The resulting regulatory liability related to the MDMS computer hardware would be adjusted based on the results of the reconciliation and would represent the advanced recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the MDMS computer hardware costs to the previous year's actual revenue requirements related to the MDMS computer hardware cost recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

MDMS DEFERRED SOFTWARE DEVELOPMENT COSTS

For book accounting purposes, the development of the MDMS software will be accounted for in accordance with accounting standards EITF 97-13 and SOP 98-1[3]. The MDMS software will be developed and placed into service in 3 phases. Each phase will be placed into service upon completion of all substantial testing (AMI project team will notify Corporate Accounting). Amortization of the deferred costs of each phase will commence in the following month for a period of 12 years (subject to PUC approval). For ratemaking purposes, the Companies propose to recover the costs of the MDMS software via the AMI surcharge over a 12-year period.

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reduce the administrative task of monitoring the accounting for the AMI project, the Companies will record the difference to the regulatory liability account.

3 Accounting guidance refers to Emerging Issues Task Force Bulletin 97-13, "Accounting for Costs Incurred in Connection with a Consulting Contract or an Internal Project that Combines Process Reengineering and Information Technology Transformation (EITF 97-13) and FASB Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use".

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MDMS Deferred Software Development:
The Company will create workorders, for each phase, to track and capture the development of the MDMS computer software. AFUDC will be manually calculated and applied to the deferred costs during development of the computer software. The following monthly entries will be recorded to account for the MDMS computer software development. This methodology is consistent with other PUC-approved software development projects of the Company.

JE #16 Dr. Deferred charges (Workorder – Software development deferred costs)
Cr. Accounts payable
This entry will capture the deferred costs of the software development phase of the project.

JE #17 Dr. Deferred charges (Workorder – Software development deferred costs)
Cr. AFUDC debt
Cr. AFUDC equity
This entry will be calculated and recorded by Corporate Accounting at the end of each month (based on the current month's AFUDC rate applied to the accumulated deferred costs) until the phase is placed into service.

JE #18 Dr. Expense (Workorder – MDMS-related expenses)
Cr. Deferred charges (Workorder – Software development deferred costs)
The Companies' Ellipse system automatically applies overhead charges to deferrable labor costs. However, only certain overhead charges are deferrable. Therefore, at the end of each month, this entry will be calculated and recorded by General Accounting to reclassify non-deferrable overhead charges to expense.

MDMS Deferred Software Amortization:
This monthly recurring journal entry will be recorded by Corporate Accounting for the amortization of the MDMS deferred software as each phase is placed into service. The amortization expense will be based on a period approved by the PUC (the Companies have proposed a 12-year amortization period) and will commence in the month following placing each phase into service.

JE #19 Dr. Amortization expense – MDMS deferred software costs
Cr. Deferred charges – MDMS deferred software costs

MDMS Deferred Software Recovery:
The Companies plan to recover the MDMS deferred software costs, via the AMI surcharge, following Commission approval of the AMI Project and AMI surcharge. There may be timing issues related to the commencement of the MDMS amortization and recovery of the MDMS software costs via the surcharge since the surcharge is adjusted at January 1 of each year (based on upcoming year's forecasted costs), but amortization may not commence until later in the year. If the monthly AMI surcharge revenues related to MDMS-deferred software recovery (JE #1) are MORE than the monthly actual amortization expenses incurred (JE #19), then this monthly entry will be recorded for the difference:

JE #20 Dr. AMI surcharge revenues by rate schedule – MDMS deferred software
Cr. Regulatory liability – MDMS deferred software

If the monthly AMI surcharge revenues related to MDMS-deferred software recovery (JE #1) are LESS than monthly actual amortization expenses (JE #19), then this monthly entry will be recorded for the difference:

JE #21 Dr. Regulatory liability[4] – MDMS-deferred software
Cr. Amortization expense – MDMS deferred software costs

The creation of any deferred tax liability (or asset) as a result of accounting for the deferred MDMS deferred software will be included as a deduction to rate base (addition if deferred tax asset).

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the MDMS deferred software would be adjusted based on the results of the reconciliation and would represent the advanced recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the MDMS deferred software costs to the previous year's actual revenue requirements related to the MDMS deferred software cost recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

MDMS-RELATED EXPENSES

For book accounting purposes, the Companies will create separate expense workorders to track and capture MDMS-related expenses (e.g., training, process and change management, support and maintenance) as they are incurred. For ratemaking purposes, the Companies propose to recover these MDMS-related expenses through the AMI surcharge. The following entry will be recorded to capture MDMS-related expenses:

JE #22 Dr. Expense workorder – MDMS-related expenses
Cr. Accounts payable

MDMS-Related Expenses Recovery:
The monthly AMI surcharge, commencing January 1, following Commission approval of the AMI Project and AMI surcharge, will be based on forecasted expenses. As such, there may potentially be differences in 1) the timing of the incurrence of these expenses and the recovery of them, and 2) the amount of actual

[4] *See footnote 1.*

expenses incurred versus the amount recovered. The Companies will monitor these potential differences on a monthly basis. The amount of the monthly AMI surcharge revenues related to MDMS-related expenses (JE #1) will be compared to the monthly incurred expenses of the MDMS-related expense workorders (JE #22). If the monthly revenues are LESS than the actual monthly MDMS-related expenses incurred, then this monthly entry will be recorded for the difference:

JE #23 Dr. Regulatory liability[5] – MDMS-related expenses
Cr. Expense workorder – MDMS-related expenses

If the monthly AMI surcharge revenues related to MDMS-related expenses (JE #1) are MORE than the actual monthly MDMS-related expenses incurred (JE #22), then this monthly entry will be recorded for the difference:

JE #24 Dr. AMI surcharge revenues by rate schedule – MDMS-related expenses
Cr. Regulatory liability – MDMS-related expenses

In JE *#23, the expense workorder will be credited in order to defer the expenses (in excess of MDMS* expenses included in the AMI surcharge revenues) until recognized against amounts collected through the AMI surcharge revenues. Similarly, in JE #24, the monthly AMI surcharge revenues (in excess of MDMS-related expenses) will be deferred until recognized against future MDMS-related expenses.

<u>Annual Reconciliation:</u>
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the MDMS-related expenses would be adjusted based on the results of the reconciliation and would represent the over-recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the MDMS-related expenses to the previous year's actual revenue requirements related to the MDMS-related expense recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

AMI NETWORK CAPITAL COSTS

For book accounting purposes, the Companies propose to capitalize the installed costs of the AMI network computer hardware and depreciate the AMI network computer hardware over the current PUC-approved depreciation rate for computer hardware, beginning January 1 of the following year the computer hardware is placed into service. The Companies propose that ratemaking treatment follow book accounting treatment.

[5] See footnote 1.

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AMI Network Capital Purchase:
The Company will create a workorder to track and capture the AMI network computer hardware purchase. AFUDC will not be applied to the costs of the purchased AMI network computer hardware as the computer hardware will be recorded to the Company's plant-in-service accounts in the month purchased. The following monthly entries will be recorded by Property Accounting (in the same month), to record the AMI network computer hardware purchase. This methodology is consistent with the Company's procedure of purchasing computer hardware.

JE #25 Dr. Construction work-in-progress workorder – AMI network computer hardware
Cr. Accounts payable
The purpose of this entry is to capture the cost of the AMI network computer hardware purchase.

JE #26 Dr. Plant-in-service – AMI network computer hardware
Cr. Construction work-in-progress
This entry is recorded at the end of the month to record the AMI network computer hardware into the Company's plant-in-service accounts.

AMI Network Computer Hardware Depreciation:
This monthly recurring journal entry will be recorded by Corporate Accounting (as calculated by Property Accounting), beginning January 1 of the following year the AMI network computer hardware is placed into service, as part of the Company's monthly depreciation entries, however will be tracked separately for the purposes of this AMI Project. The depreciation expense will be based on current PUC-approved depreciation rates for computer hardware and on the ending computer hardware balance of the previous year.

JE #27 Dr. Depreciation expense – AMI network computer hardware
Cr. Accumulated depreciation

AMI Network Computer Hardware Recovery:
The Companies plan to recover the AMI network computer hardware costs, via the AMI surcharge, following Commission approval of the AMI Project and AMI surcharge. As previously mentioned above, the Companies propose that ratemaking treatment follow book accounting treatment (i.e., the recovery of the AMI network computer hardware will occur as the AMI network computer hardware is depreciated). If the monthly AMI surcharge revenues related to AMI network-computer hardware recovery (JE #1) are LESS than the monthly actual depreciation expenses (JE #27), then this monthly entry will be recorded for the difference:

JE #28 Dr. Regulatory liability[6] – AMI network computer hardware
Cr. Depreciation expense – AMI network computer hardware

[6] See footnote 1.

If the monthly AMI surcharge revenues related to AMI network computer hardware recovery (JE #1) are MORE than monthly actual depreciation expenses (JE #27), then this monthly entry will be recorded for the difference:

JE #29 Dr. AMI surcharge revenues by rate schedule – AMI network computer hardware
Cr. Regulatory liability – AMI network computer hardware

The creation of any deferred tax liability (or asset) as a result of accounting for the AMI network computer hardware will be included as a deduction to rate base (addition if deferred tax asset).

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the AMI network computer hardware would be adjusted based on the results of the reconciliation and would represent the advanced recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the AMI network computer hardware costs to the previous year's actual revenue requirements related to the AMI network computer hardware cost recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

AMI NETWORK LEASE COSTS

The Companies' AMI proposal involves the use of a Sensus-owned, operated and maintained AMI network in exchange for a monthly, per-meter fee, to be imposed upon the deployment of each respective meter, in accordance with the provisions of the Sensus agreement. The Company completed an evaluation of the Sensus agreement and had concluded the agreement should be accounted for as an operating lease.

AMI Network Lease Payments:
For book accounting purposes, and in accordance with SFAS 13[7], the Companies must recognize lease expenses on a straight-line basis over the 15-year term beginning with the effective date of the lease (i.e., PUC approval). The straight-line lease expense amount will be determined at the inception of the lease based on the estimated number of meters to be installed per the Sensus agreement. For ratemaking purposes, the Companies propose to recover the lease payments as they are paid over the term of the lease. In the early years of the 15-year lease term, the straight-line lease expenses will be in excess of the actual lease payments made. Therefore, regulatory asset and deferred credit balances will be recognized for the difference and will grow over the early years of the lease term. Eventually, as the lease progresses through the 15-year term, the actual lease payments will exceed the straight-line lease

[7] FASB Statement of Financial Accounting Standards No. 13, "Accounting for Leases".

expense which will reduce the regulatory asset and deferred credit balances to zero by the end of the lease term. A workorder will be created to track and capture the lease payments.

A monthly recurring journal entry will be calculated and recorded by Corporate Accounting. If the monthly straight-line lease expense is GREATER than the actual monthly lease payment, then this monthly entry will be recorded when payment is made:

JE #30 Dr. Lease expense workorder (actual lease payment amount)
Dr. Regulatory asset – AMI Sensus network lease (difference between straight-line lease amount and actual lease payment)
Cr. Accounts payable (actual lease payment amount)
Cr. Misc deferred credit – AMI Sensus network lease (difference between straight-line lease amount and actual lease payment)

If the monthly straight-line lease expense is LESS than the actual monthly lease payment, then this monthly entry will be recorded when payment is made:

JE #31 Dr. Lease expense workorder (actual lease payment amount)
Dr. Misc deferred credit – AMI Sensus network lease (difference between straight-line lease amount and actual lease payment)
Cr. Accounts payable (actual lease payment amount)
Cr. Regulatory asset – AMI Sensus network lease (difference between straight-line lease amount and actual lease payment)

<u>AMI Network Lease Costs Recovery:</u>
The Companies propose to recover the lease payments as they are paid over the term of the lease. The monthly surcharge for the recovery of the AMI network lease costs will be recorded as billed revenues by rate schedules and by ACCESS (JE #1). If the monthly AMI surcharge revenues related to the AMI network lease recovery (JE #1) are LESS than the actual monthly lease payment (JEs #30/31), then this monthly entry will be recorded for the difference:

JE #32 Dr. Regulatory liability[8] – AMI network lease
Cr. Lease expense workorder – AMI network lease

If the monthly AMI surcharge revenues related to the AMI network lease recovery (JE #1) are MORE than the actual monthly lease payment (JEs #30/31), then this monthly entry will be recorded for the difference:

JE #33 Dr. AMI surcharge revenues by rate schedule – AMI network lease
Cr. Regulatory liability – AMI network lease

In JE #32, the AMI lease expense workorder will be credited in order to defer the expenses (in excess of AMI lease expense included in the AMI surcharge) until recognized against amounts collected through

[8] See footnote 1.

the AMI surcharge. Similarly, in JE #33, the monthly AMI surcharge revenues (in excess of AMI lease expenses) will be deferred until recognized against future AMI lease expenses.

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the AMI network lease expense would be adjusted based on the results of the reconciliation and would represent the over-recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the AMI network lease expenses to the previous year's actual revenue requirements related to the AMI network lease recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

AMI NETWORK-RELATED EXPENSES

For book accounting purposes, the Companies will create separate expense workorders to track and capture AMI network-related expenses (e.g., support and maintenance) as they are incurred. For ratemaking purposes, the Companies propose to recover these AMI network-related expenses through the AMI surcharge. The following entry will be recorded to capture AMI network-related expenses:

JE #34 Dr. Expense workorder – AMI network-related expenses
Cr. Accounts payable

AMI Network-Related Expenses Recovery:
The monthly AMI surcharge, commencing January 1, following Commission approval of the AMI Project and AMI surcharge, will be based on forecasted expenses. As such, there may potentially be differences in 1) the timing of the incurrence of these expenses and the recovery of them, and 2) the amount of actual expenses incurred versus the amount recovered. The Companies will monitor these potential differences on a monthly basis. The amount of the monthly AMI surcharge revenues related to the AMI network-related expenses (JE #1) will be compared to the monthly incurred expenses of the AMI network expenses workorders (JE #34). If the monthly revenues are LESS than the actual monthly AMI network-related expenses, then this monthly entry will be recorded for the difference:

JE #35 Dr. Regulatory liability[9] – AMI network-related expenses
Cr. Expense workorder – AMI network-related expenses

If the monthly AMI surcharge revenues related to AMI network-related expenses (JE #1) are MORE than the actual monthly AMI network-related expenses incurred (JE #34), then this monthly entry will be recorded for the difference:

[9] See footnote 1.

GENERAL ACCOUNTING GUIDELINES FOR THE
ADVANCED METER INFRASTRUCTURE SURCHARGE

(Updated as of June 5, 2009)

DRAFT

JE #36 Dr. AMI surcharge revenues by rate schedule – AMI network-related expenses
Cr. Regulatory liability – AMI network-related expenses

In JE #35, the expense workorder will be credited in order to defer the expenses (in excess of AMI network-related expenses included in the AMI surcharge) until recognized against amounts collected through the AMI surcharge. Similarly, in JE #36, the monthly revenues (in excess of AMI network-related expenses) will be deferred until recognized against future AMI network-related expenses.

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the AMI network-related expenses would be adjusted based on the results of the reconciliation and would represent the over-recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the AMI network-related expenses to the previous year's actual revenue requirements related to the AMI network-related expense recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

OTHER AMI-RELATED COSTS – DAMAGED METER SOCKET COSTS

For book accounting purposes, the Companies will create separate expense workorders to track and capture damage meter socket costs as they are incurred. For ratemaking purposes, the Companies propose to recover these damage meter socket costs through the AMI surcharge. The following entry will be recorded to capture the damage meter socket costs:

JE #37 Dr. Expense workorders – damage meter socket costs
Cr. Accounts payable

Damage Meter Socket Costs Recovery:
The monthly AMI surcharge, commencing January 1, following Commission approval of the AMI Project and AMI surcharge, will be based on forecasted expenses. As such, there may potentially be differences in 1) the timing of the incurrence of these costs and the recovery of them, and 2) the amount of actual damage meter socket costs incurred versus the amount recovered. The Companies will monitor these differences on a monthly basis. The amount of the monthly AMI surcharge revenues related to damage meter socket costs (JE #1) will be compared to the monthly costs of the damage meter socket workorders (JE #37). If the monthly revenues are LESS than the actual monthly damage meter socket costs incurred, then this monthly entry will be recorded for the difference:

JE #38 Dr. Regulatory liability – damage meter socket costs
Cr. Expense workorder – damage meter socket costs

GENERAL ACCOUNTING GUIDELINES FOR THE
ADVANCED METER INFRASTRUCTURE SURCHARGE

(Updated as of June 5, 2009)

DRAFT

If the monthly AMI surcharge revenues related to damage meter socket costs (JE #1) are MORE than the actual monthly damage meter socket costs (JE #37), then this monthly entry will be recorded for the difference:

JE #39 Dr. AMI surcharge revenues by rate schedule – damage meter socket costs
Cr. Regulatory liability – damage meter socket costs

In JE #38, the expense workorder will be credited in order to defer the costs (in excess of damage meter socket expenses included in the AMI surcharge) until recognized against amounts collected through the AMI surcharge. Similarly, in JE #39, the monthly revenues (in excess of damage meter socket costs) will be deferred until recognized against future damage meter socket costs.

<u>Annual Reconciliation:</u>
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to the damage meter socket costs would be adjusted based on the results of the reconciliation and would represent the over-recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the damage meter socket costs to the previous year's actual revenue requirements related to the damage meter socket costs recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

OTHER AMI-RELATED COSTS – OUTSIDE CONSULTING COSTS

For book accounting purposes, the Companies will create separate expense workorders to track and capture outside consulting costs as they are incurred. For ratemaking purposes, the Companies propose to recover these outside consulting costs through the AMI surcharge. The following entry will be recorded to capture the outside consulting costs:

JE #40 Dr. Expense workorders – outside consulting costs
Cr. Accounts payable

<u>Outside Consulting Costs Recovery:</u>
The monthly AMI surcharge, commencing January 1, following Commission approval of the AMI Project and AMI surcharge, will be based on <u>forecasted</u> expenses. As such, there may potentially be differences in 1) the timing of the incurrence of these costs and the recovery of them, and 2) the amount of actual outside consulting costs incurred versus the amount recovered. The Companies will monitor these differences on a monthly basis. The amount of the monthly AMI surcharge revenues related to outside consulting costs (JE #1) will be compared to the monthly costs of the outside consulting workorders (JE

#40). If the monthly revenues are LESS than the actual monthly outside consulting costs incurred, then this monthly entry will be recorded for the difference:

JE #41 Dr. Regulatory liability – outside consulting costs
Cr. Expense workorder – outside consulting costs

If the monthly AMI surcharge revenues related to outside consulting costs (JE #1) are MORE than the actual monthly outside consulting costs (JE #40), then this monthly entry will be recorded for the difference:

JE #42 Dr. AMI surcharge revenues by rate schedule – outside consulting costs
Cr. Regulatory liability – outside consulting costs

In JE #41, the expense workorder will be credited in order to defer the costs (in excess of outside consulting costs included in the AMI surcharge) until recognized against amounts collected through the AMI surcharge. Similarly, in JE #42, the monthly revenues (in excess of outside consulting costs) will be deferred until recognized against future outside consulting costs.

Annual Reconciliation:
For book accounting purposes, quarterly reconciliations will be performed in connection with analyzing the recorded entries above. The resulting regulatory liability related to outside consulting costs would be adjusted based on the results of the reconciliation and would represent the over-recovery or under-recovery (if the regulatory liability is negative – see footnote 1) to-date. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual revenue requirements related to the outside consulting costs to the previous year's actual revenue requirements related to the outside consulting costs recoveries through the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

OFFSETTING INCREMENTAL BENEFITS (SUBJECT TO FURTHER DISCUSSION)

Note: Refer to part c of the Company's response to CA-IR-36 of the AMI proceeding (Docket No. 2008-0303) for discussion on the calculation and determination of the benefits.

Energy Theft Recovery, Meter Accuracy Gains, Meter Reading Savings and Field Services Savings Benefits:
For book accounting purposes, the energy theft recoveries and meter accuracy gains will be embedded in the recorded revenues, which will be higher than they would have been without the energy theft recoveries and meter accuracy gains. Similarly, the meter reading and field services savings will be embedded in the meter reading and field services expenses, respectively, which will be lower than they would have been but for the AMI project. See response to part c of CA-IR-36 for the determination.

For ratemaking purposes, higher sales and thus higher revenues from the energy theft recoveries and meter accuracy gains, lower meter reading expenses and lower field services expenses will be incorporated in the AMI surcharge, to the extent that they are not reflected in base rates[10] or other rates. For meter reading savings and field services savings, on a monthly basis and until these benefits are reflected in base rates, the AMI project team and/or Energy Services (yet to be determined) will provide the actual incremental benefits by cost component to Corporate Accounting in order to properly reflect the benefits in the AMI surcharge.

Annual Reconciliation:
For book accounting purposes, analyses of the net benefits will be taken into consideration when performing the quarterly reconciliations of the project cost components noted above. For ratemaking purposes, on an annual basis, Energy Services Division (in cooperation with Corporate Accounting) will reconcile the previous year's actual net benefits to the previous year's actual net benefits embedded in the AMI surcharge. The current year's surcharge that was effective January 1, would be adjusted on March 1 for the over or under-collections (along with monthly interest charged or credited), and effective March 1 through December 31 of the remainder of the current year.

RATE BASE SUMMARY

The Company proposes to include the following items in its rate base.

- New AMI Meters, Regulatory Liability – New AMI Meters
- Existing Non-AMI Meters (until replaced), Regulatory Liability – Existing Non-AMI Meters
- MDMS Capital Costs, Regulatory Liability – MDMS Capital Costs
- MDMS Deferred Software Development Costs, Regulatory Liability – MDMS Deferred Software Development Costs
- AMI Network Capital Costs, Regulatory Liability – AMI Network Capital Costs
- Regulatory liabilities (or assets) created as a result of accounting for the capital and deferred costs of the AMI project, including the new AMI meters and non-AMI meters

The following items are not included in rate base.

- MDMS-Related Expenses Regulatory Asset or Liability
- AMI Network Lease Costs Regulatory Asset or Liability (related to the cost recovery)
- AMI Network-Related Expenses Regulatory Asset or Liability
- Other AMI-Related Costs – Damaged Meter Socket Costs Regulatory Asset or Liability
- Other AMI-Related Costs – Outside Consulting Costs Regulatory Asset or Liability

The regulatory asset and deferred credit related to straight-lining of the AMI network leases will not be included in rate base. Also, interest will not accrue on this regulatory asset and deferred credit.

10 Assuming sales decoupling is approved, the impact of energy theft recovery and meter accuracy gains will be reflected as part of the revenue balancing account in the sales decoupling mechanism.

Meter Reading Estimated Manning

HECO	[1] No-AMI	[2] With AMI
Field Reps / Supervisors / Clerks / Planners	20	12

HELCO	No-AMI	With AMI
Field Reps / Supervisors / Clerks / Planners	10	6

MECO	No-AMI	With AMI
Field Reps / Supervisors / Clerks / Planners	6	4

[1] CA-IR-2, Attachment 1, Section X.E.2
[2] CA-IR-2, Attachment 1, Section X.E.4

Hawaiian Electric Co.
Revenue Protection
Monthly Statistics
2008

Month Year	*Reports Received*	*Reports Closed**	*No of BillsIssued*	*KWH Billed*	*Energy Billed*	*Material Costs*	*Total Billed*	*Not Billed Labor Expense*	*Payments*	*Adjustments*
January 2008	61	1	4	17,021	$3,548	$634	$4,183	$0	$2,564	$0
February 2008	205	6	7	3,644	$885	$1,168	$2,053	$0	$3,481	$0
March 2008	84	28	5	20,984	$4,744	$386	$5,130	$0	$6,516	$0
April 2008	181	40	8	669,091	$228,947	$638	$229,585	$0	$1,408	$0
May 2008	224	25	18	280,605	$88,627	$1,701	$90,328	$0	$231,508	$0
June 2008	234	35	5	97,082	$13,079	$711	$13,790	$0	$3,417	$0
July 2008	256	35	8	17,194	$4,639	$928	$5,567	$0	$3,229	$0
August 2008	224	63	5	28,091	$6,913	$665	$7,577	$0	$2,564	$0
September 2008	94	29	10	1,392,337	$323,987	$530	$324,517	$0	$359,983	$0
October 2008	54	40	11	613,103	$178,860	$1,122	$179,983	$0	$86,814	$0
November 2008	21	150	7	122,894	$24,267	$684	$24,950	$0	$135,536	$0
December 2008	24	24	4	5,192	$1,485	$314	$1,799	$0	$5,731	$0
Totals:	**1,662**	**476**	**92**	**3,267,238**	**$879,982**	**$9,480**	**$889,462**	**$0**	**$842,750**	**$0**

CA-IR-36
DOCKET NO. 2008-0303
ATTACHMENT 3
PAGE 1 OF 1

**** No. of Reports Closed can exceed Reports recd because of carryover from previous year(s)***

HSEA-HREA-IR-1

Please provide more detail on the short and long term goals of the combined AMI/TOU application, and the timelines and cost savings (if any) associated with these goals including:

a. How does the proposed peak vs. non-peak structure accomplish load shifting?
b. Does any shifting of load reduce the cost of service? If so, please provide information on the magnitude of this savings and the specific mechanisms through which it is realized.
c. Does the value realized via cost of service gains vary over the course of day? If so, please provide information on the magnitude of the variation in these savings and the specific mechanisms through which they are realized.
d. Is reducing use a goal?
e. If reducing use is a goal, please explain how the HECO Companies proposal is more or less effective at reducing use than inclining block rates.
f. If reducing use is a goal, do the HECO companies plan to implement a specific program on each island or for each utility?
g. Would any such programs to reduce use involve determining desired load reductions by customer class?

HECO Companies' Response:

The goal of the TOU portion of the AMI application was to meet the requirement of Section 14 of the *Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce & Consumer Affairs, and the Hawaiian Electric Companies*, wherein the HECO Companies agreed to apply to the Commission by November 30, 2008 to seek approval to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them. This application also seeks expedited approval to fully implement time-of-use rates on an interim basis for the customers requesting the installation of advanced meters.

a. The proposed peak vs. non-peak structure illustrated in Exhibit 25 of the application provides an option for the Companies' customers to respond to the optional tariff pricing signals to minimize their electric bills. The time-of-use rate options provide a financial incentive to shift load from peak periods to non-peak periods. Actual load shifting will depend on actual customer response under these rates.

b. The Companies have no studies to quantify that shifting of load will reduce the overall cost of service. There may be differences in energy costs depending on the amount and the timing of shifted load. To the extent that load shifts become a long-term change in behavior, load shifts can reduce future cost of service by reducing future peak loads.

c. See response b above.

d. Yes. The HECO Companies have supported reduction in energy use through their energy efficiency programs for many years.

e. The time-of-use rate options that the HECO Companies have proposed in their rate cases and that are proposed in the instant application are designed to encourage load shifting, not load reduction. All of the HECO Companies have proposed inclining block rates for residential customers in open rate cases currently before the Commission.

f. See the responses to d and e above.

g. Not applicable. See responses d and e above.

HSEA-HREA-IR-2

TOU and Inclining Block Rates

a. Have the HECO Companies considered mechanisms besides time of use rates in order to accomplish the short and long term goals discuss in HSEA/HREA IR-1? If so, please list and describe these other mechanisms, and explain why time of use is preferable for accomplishing each of these goals.
b. How, if at all, will TOU rates be related to and/or co-implemented with inclining block rates?
c. How will TOU rates be implemented with respect to inclining block rates by customer class?
d. What is the timeline for doing so?

HECO Companies' Response:

a. As indicated in the response to HSEA-HREA-IR-1, the time-of-use ("TOU") rates were proposed in conjunction with the AMI application as part of the HECO Companies' commitments under the *Energy Agreement with the State of Hawaii and the Division of Consumer Advocacy*. TOU rates are one of several mechanisms that can be used to influence the timing and amount of customer energy use. It is not a question of using only one mechanism.
b. In the instant application, the proposed residential time-of-use rates include usage charges that are proposed for inclining usage blocks as shown in Exhibit 25 of the application.
c. TOU rates with inclining blocks are only proposed for the residential customer class.
d. The Companies will implement the TOU rates in a manner and timeline as dictated by an affirmative Commission Decision and Order in the instant docket.

HSEA-HREA-IR-3

With respect to demand response:

a. Will the HECO Companies implement a demand response program?
b. If so, how will that be accomplished?
c. If so, what is the timeline for doing so for each utility?
d. If so, which customer classes will be affected?
e. If so, what is the budget for any demand response programs?

<u>HECO Companies' Response:</u>

a. Yes.

b. HECO, MECO, and HELCO also have proposed new time-of-use ("TOU") rate options in their pending rate cases. While each Company currently has TOU options, the proposed rates will make TOU options available for nearly all rate schedules at MECO and HELCO.[1] The TOU rates use time-based rates to encourage customers to shift load out of the on-peak periods and into off-peak periods.

On April 24, 2008, HECO filed an application for a dynamic pricing pilot ("DPP") program on Oahu (Docket No. 2008-0074). The objective of the pilot is to determine whether dynamic pricing is a viable approach to demand reduction for reliability enhancement, identify cost and implementation issues in advance of a possible island-wide rollout of a residential demand response program, and determine customer program adoption rates and satisfaction with the program.

Under the proposed pilot, 600 participating residential customers will be subject to peak time rebates during critical peak periods identified by HECO. The peak time rebate is $1 for every kWh saved during the critical peak period. Approximately 400 of

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[1] The Companies did not propose a TOU option for Schedule F, Street and Playground Lighting, because Schedule F customers do not have significant flexibility in moving load.

the 600 participants will have central air-conditioning, of which about 200 will be provided with a programmable thermostat. When the critical peak period is initiated, the temperature set point for the central air-conditioners will be remotely increased by 4 degrees. This automatic response can be overridden by the participant.

Pilot participants will also be encouraged to reduce their consumption by manually reducing the use of other electrical end-uses. The pilot is a demand response program because the application of price incentives is expected to result in changes in customer electricity consumption behavior.

Following the one-year pilot, HECO proposes to evaluate the results and determine whether peak time rebates or other forms of pricing signals should be deployed for all residential customers or for all commercial customers. AMI meters that can collect, store, and transmit time-based use data and a meter data management system ("MDMS") are essential if a large expansion of the proposed pilot or a resulting full-scale deployment is to be successful.

The Consumer Advocate filed its Statement of Position ("SOP") on the Dynamic Pricing Pilot (DPP) program in February 2009. In its SOP, the Consumer Advocate recommended that the DPP program be modified to consider other forms of pricing signals and that HECO include other residential appliances as a load control program, among other recommendations. HECO is preparing its response to the SOP, which may include modifications of its DPP program.

HECO's application to renew its Commercial & Industrial Direct Load Control ("CIDLC") Program was filed on March 31, 2009 (Docket No. 2009-0073). Included in the application is an initial plan of action to work with third-party demand response or load curtailment aggregators on a pilot basis to develop price-responsive demand response options for customers. This aggregator pilot also targets the use of demand response as a mechanism to accommodate more renewable energy and as a tool to manage frequency fluctuations resulting from intermittent renewable resources connected to the Company's system grid. As part of the plan of action, HECO intends to issue an RFP during the third quarter of 2009 and be ready to implement the aggregator pilot in 2010. The implementation of the aggregator pilot is expected to require the filing of an application with the Commission by December 2009.

MECO's current plan is to file for the implementation of new demand response programs on or about June 30, 2009.

HELCO is evaluating its options for demand response programs, including both residential and commercial direct load management programs. Although it currently has sufficient reserve generating capacity, as well as nearly 8 MW of peak load curtailment capacity, preliminary avoided cost analysis has shown that direct load management options may be feasible as early as 2015. However, HELCO may develop pilot load management programs earlier in order to test market response, as well as operating strategies that could enable the integration of additional as-available renewable energy.

Much of how the Companies address demand response will be determined by the results of these initial pilots and programs and in the long-term by the timing of AMI meter and MDMS deployment. Therefore, a complete picture of the end-uses, operational procedures, and data processing steps involved in demand response in Hawaii will be better understood upon completion of the evaluation of the proposed Aggregator pilot and the DPP program. Nevertheless, the HECO Companies maintain that the implementation of demand response strategies is a key component of maintaining system reliability and accommodating more renewable energy on the utility system.

c. As indicated in part b. above, the DPP program application is pending before the Commission. On February 18, 2009, the Consumer Advocate filed its SOP on the DPP program. HECO is currently preparing a reply SOP. Upon Commission approval of the program, HECO expects that it will immediately begin with participant recruitment and subsequent meter installation. Application of peak time rebates is expected to occur thereafter and last for 12 months. Following a few months for evaluation, HECO will decide whether or not to deploy dynamic pricing to all residential customers. HECO will also determine whether or not to deploy dynamic pricing for its commercial customers. HECO's aggregator pilot is scheduled to begin in 2010, pending Commission approval of the CIDLC Program's renewal and approval of the aggregator pilot application that will be filed by December 2009.

Based on its current plan, MECO's demand response programs are expected to begin in early 2010, pending Commission approval; and HELCO's demand response programs are expected to begin in 2015 following the development of suitable programs and operating strategies, and Commission approval of same.

Full deployment of dynamic pricing is dependent on full deployment of AMI meters and on the availability of a MDMS capable of handling time-based meter data.

d. See response to part c. above.

e. The incremental budget for the DPP program included in HECO's application is $337,500. However, because the DPP program may be modified in response to the Consumer Advocate's SOP, the incremental budget may change. HECO has not developed a budget estimate for full-scale deployment of the DPP program. The cost of HECO's aggregator pilot will not be known until responses to the RFP are received later this year.

MECO's costs for its demand response programs are still being finalized and will be included in its applications currently planned to be filed no later than June 30, 2009. HELCO has not completed a cost estimate for its demand response programs, which are pending additional analysis. These estimates will be based in part on the responses received from each company's RFP process.

HSEA-HREA-IR-4

How will the HEC Companies' time of use programs proposed in this docket be coordinated with the following:

a. Time of use efforts underway between the HECO Companies and the Department of Defense?
b. Other DOD programs intended to shift load or reduce use through pricing?
c. The activities of the Public Benefits Fee Administrator?

HECO Companies' Response:

a. Time-of-use rate options proposed in this docket will be made available to Department of Defense ("DOD") customers and all other customers upon Commission approval. In fact, time-of-use rate options for all HECO (Oahu) customer classes were approved in HECO's 2005 rate case (Docket No. 04-0113) and are available currently. HECO personnel who work with DOD accounts are able to provide advice as to time-of-use rate options and other available rate rider options available.
b. See response a above.
c. Time-of-use rate options proposed in this docket will be available to all customers, including customers that participate in energy efficiency programs that are coordinated by the Public Benefits Fee Administrator.

HSEA-HREA-IR-5

Please list in detail any additional costs that ratepayers with advanced meters will have to bear. (i.e., will a ratepayer need to purchase, rent, lease, or license any additional hardware or software following the installation of an advanced meter at his/her location in order to fully implement the system?)

HECO Companies' Response:

The proposed AMI system does not require ratepayers to purchase, rent, lease, or license additional hardware or software. The proposed AMI system will consist of AMI meters, the AMI network, Meter Data Management System (MDMS), and a web portal for customers with Internet access. Customer access to electricity consumption will be provided through a web portal that displays time-differentiated electricity consumption.

End-use devices such as in-premise displays, smart thermostats and load control switches may be used in future program offerings enabled by the AMI platform but are not part of Docket No. 2008-0303.

HSEA-HREA-IR-6

Will a ratepayer be required to opt in to TOU billing structure in order to receive an advanced meter?

<u>HECO Companies' Response:</u>

Customers requesting an AMI meter prior to a general AMI meter rollout will be placed on the appropriate TOU billing rate as the default rate effective the next billing cycle after the installation of the AMI meter. However, the TOU rates are optional and customers will be able to opt out of the TOU rates by notifying the utility company of their desire to do so.

Customers receiving a non customer-initiated installation of an AMI meter during the general AMI roll-out period, but before the completion of a full roll-out of AMI meters, will remain on their current rate schedule or may choose to opt into the appropriate TOU billing rate. Customers will be able to opt into a TOU rate by notifying the utility company of their desire to do so with the appropriate TOU rate effective the next billing cycle after the provision of notice to the company.

At the completion of the general roll-out of AMI, all commercial customers will be placed on a mandatory TOU rate subject to the availability of the Meter Data Management System (MDMS) and a Customer Information System (CIS) capable of handling the volume of transactions required; and in accordance with the HECO Companies' commitments under the Energy Agreement with the State of Hawaii and the Division of Consumer Advocacy, section 15, Pricing Principles and Programs.

HSEA-HREA-IR-7

Please describe in detail the process for a ratepayer opting in to TOU billing.

HECO Companies' Response:

A customer requesting an AMI meter will be placed on the optional TOU rate as the default rate effective the next billing cycle after the installation of the AMI meter.

HSEA-HREA-IR-8

For the following list, please describe the process through which the HECO Companies evaluated each list item, the criteria involved in evaluation of competing options, and the relative merits of the selected technologies in relation to alternatives that were not selected:

a. The proposed software systems
b. The proposed hardware systems
c. The overall system comprised of the proposed hardware and software systems

HECO Companies' Response:

a. The proposed software system is part of the Meter Data Management System ("MDMS"). In 2007, HECO hired Enspiria Solutions ("AMI/MDM consultant") to develop preliminary functional requirements for the MDMS and to identify several candidate MDMS vendors[1] to explore under an R&D project. The primary intent of this initial work was to provide the HECO companies with a better understanding of the standard features, ease of interfacing and use, quality of the user interface, software installation complexity and requirements, and limitations associated with commercial, off-the-shelf MDMS software.

Due to the rapidly evolving MDMS product marketplace, the development of embedded demand response ("DR") capability in MDMS products[2], discussions and meetings with mainland utilities, and vendor discussions at various conferences, HECO decided to expand the MDMS product evaluations to three additional MDMS vendors[3], with onsite, hands-on demonstrations for the HECO companies.

HECO will be working with an MDMS/AMI consultant to develop a comprehensive MDMS RFP. The MDMS software will be put out to competitive bid in the third quarter

[1] The two vendors were eMeter and Itron.
[2] Embedded DR should work to mitigate integration risks between an MDMS and a DR system.
[3] The three additional vendors will be Aclara, Ecologic Analytics (formerly WACS), and Oracle Loadstar.

2009, with an MDMS award (contingent upon Commission approval of the AMI project) planned in the fourth quarter of 2009.

Additional software systems are employed in the AMI system, but this software will not be purchased by HECO; it will be part of the network services responsibility of Sensus Metering Systems, the AMI vendor.

b. The proposed hardware consists of AMI meters, TGB devices[4], FNP[5] devices and FRP[6] devices manufactured by Sensus Meter Systems. AMI technology selection is described in Exhibit 1 and 3 to the Companies' application in this docket, which summarize the details of the AMI Equipment and Services Agreement executed by HECO and Sensus Metering Systems. Included in the agreement is a requirement that HECO purchase 90% of its AMI meters from Sensus Metering Systems over a 15-year term. In 2007, the AMI product market was sparse and advanced AMI metering was in its infancy – products were immature, lacked features, and rapidly evolving. In 2007 and 2008, HECO built out a pilot AMI system (which now includes approximately 8,000 Sensus meters) to better understand the performance and limitations of the Sensus Metering Systems hardware and software. Early results of this pilot are presented in Exhibit 3 to the Companies' Application. The Company made a decision to focus on the use of Sensus' fixed network, and licensed RF technology, and decided not to pilot mesh network technologies from firms such as Itron, SilverSpring Networks, Elster, Landis & Gyr (Cellnet), and others, as further explained in Exhibit 3 of the Companies' Application.

[4] TGBs denote the Tower Gateway Basestations
[5] FNP denotes the FlexNet Network Portal
[6] FRP denotes the FlexNet Remote Portal

c. In light of the rapid escalation in Smart Grid activities and vendor developments related to the Smart Grid, HECO has asked its AMI/MDMS consultant to conduct an AMI industry update, which will help the Companies assess the technology selection in light of AMI's potential role in a Smart Grid. In 2009, HECO established a Smart Grid task force and initiated preliminary Smart Grid roadmapping activities shortly thereafter. With the availability of funds from the American Recovery and Reinvestment Act of 2009, this effort has been accelerated. An RFP for competitive selection of a Smart Grid consultant is schedule to be issued in mid-2009 after the detailed work scope for this work is completed.

d. For the overall AMI system, HECO is developing an RFP for competitive selection of an AMI Systems Integrator ("SI"). The SI will be responsible for the MDMS implementation as well as multiple integrations including: (1) front-end integration with the AMI vendor's software system; (2) back-end integration with the Companies' customer information system (CIS); and (3) development and integration of the customer web portal. The Companies expect to issue the RFP in the third quarter of 2009, with an SI contract awarded (contingent upon Commission approval of the AMI project) planned in the fourth quarter of 2009.

HSEA-HREA-IR-9

Can the HECO companies proposed metering system capture and calculate the following:

a. Total energy used on site?
b. Total energy exported to the grid?
c. Total output of the customer generators system?
d. Total energy delivered to the customer via the grid
e. Net sales

HECO Companies' Response:

a. Yes. The proposed AMI system's residential and commercial & industrial meters are capable of measuring, storing, and displaying delivered, received, and net energy values. "Delivered" is defined as being "delivered to the customer". "Received" is defined as "received from the customer".

b. Yes. See the response to (a) above. Energy exported to the grid would be the same as the "Received" value indicated by the AMI meter.

c. No. The output of customer generator systems would not be individually metered by the proposed AMI system. The customer would need to install a meter at the output of their generator system.

d. Yes. See the response to (a) above. Energy delivered to the customer via the grid would be the same as the "Delivered" value indicated by the AMI meter.

e. Yes. See the response to (a) above. Net energy (sales) value is computed, stored, and displayed by the AMI meter as the difference between the Delivered and Received Energy.

HSEA-HREA-IR-10

With respect to items a/b/c/d/e in HSEA/HREA IR-9, can this information be captured by the time at which it occurs?

<u>HECO Companies' Response:</u>

Yes. The proposed AMI System's residential and commercial & industrial meters are programmable to capture and timestamp interval measurements and route this information back to the System's Meter Data Management System.

HSEA-HREA-IR-11

Do the HECO Companies intend to propose any time-of delivery tariff regimes in this docket? In other existing dockets? In dockets not yet filed?

HECO Companies' Response:

The Companies are unclear as to the definition of "time-of-delivery regimes" as used in this information request. The time-of-use rate options proposed in the rate cases of the HECO Companies and the time-of-use rate options proposed in this AMI Project Application are the only time-based rates contemplated currently.

HSEA-HREA-IR-12

Please describe the justification for the HECO Companies' proposed periods for TOU billing.

<u>HECO Companies' Response:</u>

The proposed periods for Schedule TOU-R for all HECO Companies are the same as those proposed for Schedule TOU-R in HECO's 2009 test year rate case, Docket No. 2008-0083. The proposed periods for all commercial TOU rates are the same as the periods in existing commercial TOU rate options, and are also the same as those proposed for commercial TOU rates and pending approval in HELCO's 2006 test year rate case, Docket No. 05-0315; HECO's 2007 test year rate case, Docket No. 2006-0386; MECO's 2007 test year rate case, Docket No. 2006-0387; and HECO's 2009 test year rate case, Docket No. 2008-0083.

HSEA-HREA-IR-13

Please describe the justification for the magnitude of variation in pricing for different periods under TOU billing.

HECO Companies' Response:

The Companies' justification for the proposed residential TOU period pricing levels can be found in HECO's 2009 test year rate case, Docket No. 2008-0083, HECO T-22, pages 41-43; and in Exhibit 25 to the instant application, on pages 1-2.

In summary, HECO's residential TOU-R rate differentials were designed to create a greater cost differential and thus a greater incentive to move energy consumption to off-peak periods. All rate level differentials were based on the first tier non fuel energy charge plus the base fuel energy charge. Corresponding rate differentials are proposed for both MECO and HELCO residential TOU rates.

The justification for the proposed HELCO commercial TOU rates can be found in HELCO's 2006 test year rate case, Docket No. 05-0315, HELCO T-20, pages 43-50; and in Exhibit 25 to the instant application, on pages 1-2.

The justification for the proposed MECO commercial TOU rates can be found in MECO's 2007 test year rate case, Docket No. 2006-0387, MECO T-18, pages 37-44, 68-75, and 100-107; and in Exhibit 25 to the instant application, on pages 1-2.

The rate levels illustrated in the instant application were adjusted to be consistent with the current levels of energy cost adjustment at each utility.

LOL-IR-1

The purpose of the Advanced Meter Infrastructure (AMI) Project is to build the Smart Grid of tomorrow. How will it improve the grid from the capabilities of the existing grid?

The delta, the amount of improvement, is the change between the capabilities of the future grid and the capabilities of the current grid. To calculate it you need to know the capabilities of the current grid (the baseline information).

To what level can we achieve what we want to achieve with the current configurations? What will be the cost of the upgrades? Is it worth it? To understand the current capabilities, the current HECO, MECO & HELCO grids are being analyzed through various integration studies.

(a) Please provide a list of grid integration studies that have been started or completed in the past five years, including draft reports, final reports, reports in progress, and anticipated and budgeted future reports.
(b) For each report listed please identify the timeline of the report, the author. which parts are confidential and why, and who the contact person is for the utility.
(c) Please provide redacted and unredacted versions of each report.

HECO Companies' Response:

a. As described in the HECO Companies' Submission Of Supplemental Information, Appendices A-C ("Appendices A-C") filed in Docket No. 2008-0273 (the Commission's Feed-in Tariffs ("FIT") investigation), the Companies commissioned the following studies of the Companies' electric grids: (1) the General Electric Studies (HECO, MECO, and HELCO); (2) an Electric Power Research Institute ("EPRI") Study (HELCO); and (3) an Electric Power Systems Inc. Study (HELCO).

General Electric Studies

The increase of intermittent and variable renewable resources could create voltage and frequency regulation, load following, dispatch and unit commitment challenges to the operation of the Companies' grids. As a result, the utilities' electrical systems are being analyzed in various studies conducted by General Electric. This assessment is being conducted in two phases.

In Phase 1, a detailed electrical and economic model of the existing infrastructure of the Companies' grids is being developed using information and models provided by the utility and validated by General Electric, to establish a baseline condition. The transient and production costs models will be validated against utility historical data to achieve confidence in the fidelity of the approach. The main objective of the effort is to develop a baseline model of the electrical infrastructure on the utilities' grids to serve as a reference point for future scenario analyses exploring different renewable energy and mitigating measure configurations of interest to the Companies' planners. Specifically, the Phase 1 studies will develop short-term and longer-term stability models and production cost models to identify the impact on technical performance and operating economics associated with as-available generation on the utilities' grids. Adequate modeling of the grids is an essential first step of the work needed to investigate grid operation with high penetrations of as-available energy, and this effort will assist in addressing this need. After completing validation of the baseline model, the General Electric Studies will proceed to Phase 2, which will analyze the technical and economic impact of infrastructure expansion scenarios (more renewable energy and possible mitigation technologies) relative to the baseline condition.

This analysis is contemplated to provide guidance in determining the amount, if any, of additional intermittent renewable energy generation the systems can reasonably accept without unduly impacting the reliability and operability of the island grids. However, it must be acknowledged that these studies are not meant to be exhaustive in scope, but rather, are designed in particular to assess any benefits and risks associated with the different mitigating technologies that may be implemented to address issues raised by increasing levels of variable generation on the Companies' island systems. Accordingly, more in-depth analysis and additional studies will be required in order to determine the extent to which a particular system may be able to integrate a specific project, and to evaluate the particular system requirements associated with such integration.

The Phase 1 studies for both the HELCO and MECO systems have been completed. These studies are voluminous in nature. The HECO Companies are in the process of securing final electronic versions of the documents and will make the studies available to the Commission, and also to the parties via email, as soon as the electronic versions are secured. The Phase 1 study for the HECO system is in progress and anticipated to be completed in approximately July of 2009.

Preliminary results for model efficacy for the HELCO Phase 2 study are in the review process, and it is presently anticipated that a Phase 2 study will be available to the public some time during the summer of 2009. The MECO Phase 2 study is in progress and anticipated to be completed by year-end 2009.

The HECO Companies object to providing the MECO Phase 2 study on the grounds that is confidential and available only to the signatories to an August 21, 2008 settlement agreement and such other persons (including the Commission and Consumer Advocate) as the signatories shall mutually agree.

EPRI Studies

EPRI conducts research and development ("R&D") relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers, as well as experts from academia and industry to help address challenges in electricity including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range R&D planning, and supports research in emerging technologies.

EPRI members receive reports of EPRI's R&D efforts as part of their membership with EPRI. The terms and conditions of EPRI membership prevent members from freely distributing copies of EPRI reports as they are subject to license as well as copyright law. As a nonprofit organization, EPRI has the obligation to and does make its reports available to the public, for purchase or otherwise.

With respect to HELCO, EPRI is in the process of completing the production of the following two reports: (1) EPRI Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation (EPRI Product ID 1018715); and (2) Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance - Phase 2 (EPRI Product ID 1018716).

As a member of EPRI and a funder of the projects in which these reports were developed, HECO has received preliminary draft copies of the reports. HECO objects to producing the reports on the grounds that the terms and conditions of HECO's EPRI membership require HECO to treat these draft reports as confidential information. EPRI will make the final versions of the reports available for purchase by the public as soon as production of the reports has been completed.

Electric Power Systems, Inc. Report

Electric Power Systems, Inc. produced a HELCO wind integration impact study (dated December 29, 2006 and prepared by David W. Burlingame, P.E. and Dr. James W. Cote, P.E.) which provides important information regarding the issues associated with integrating intermittent renewable resources on an island grid. A copy of the study was provided as part of Appendices A-C, filed in the FIT docket.

Smart Grid Roadmapping

In light of the importance and complexity of Smart Grid investments, the HECO Companies established a Smart Grid task force in early 2009, with a goal to develop a comprehensive Smart Grid Roadmap. Due to the rapid development of the Smart Grid in the past year, there is a need to address the role and function of the Companies' proposed advanced metering infrastructure. An initial technical evaluation report entitled "Smart Grid Capability of Smart Meter Vendors" was recently completed and an RFP to engage a consulting firm to develop a detailed Smart Grid Roadmap and business case analysis is expected to be issued by July 2009.

b. Please reference the response to Part (a).

c. Please reference the response to Part (a).